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PIPELINE SAFETY: A PROGRESS REPORT SINCE THE ENACTMENT OF THE PIPELINE SAFETY IMPROVEMENT ACT OF 2002

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY AND AIR QUALITY

OF THE

COMMITTEE ON ENERGY AND COMMERCE
HOUSE OF REPRESENTATIVES

ONE HUNDRED NINTH CONGRESS

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PIPELINE SAFETY: A PROGRESS REPORT SINCE THE ENACTMENT OF THE PIPELINE SAFETY IMPROVEMENT ACT OF 2002

THURSDAY, APRIL 27, 2006

HOUSE OF REPRESENTATIVES,
COMMITTEE ON ENERGY AND COMMERCE,
SUBCOMMITTEE ON ENERGY AND AIR QUALITY,
Washington, DC.

The subcommittee met, pursuant to notice, at 10:08 a.m., in Room 2322 of the Rayburn House Office Building, Hon. Ralph M. Hall (chairman) presiding.

Members present: Representatives Wilson, Otter, Murphy, Burgess, Barton (ex officio), Boucher, Markey, Green, Gonzalez, and Hall.

Staff present: Maryam Sabbaghian, Counsel; Elizabeth Stack, Policy Coordinator; David McCarthy, Chief Counsel for Energy and Environment; Tom Hassenboehler, Counsel; Peter Kielty, Legislative Clerk; and Bruce Harris, Minority Professional Staff Member.

MR. HALL. Okay. I thank you for your patience, and I thank you for the time that you have given, are giving, and will give. And I want to begin by just discussing a little bit of what we expect and what we hope for here.

Protecting the safety of our pipeline system requires a lot of comprehensive and coordinated efforts of several Federal and State agencies and industry and pipeline safety advocacy groups.

To this end, the hearing is going to consist of three panels of witnesses, and the first panel will consist of representatives from the Department of Transportation, Pipeline and Hazardous Materials Administration and the Office of Inspector General, the National Transportation Safety Board, and the Government Accountability Office.

The second panel is going to consist of representatives from the National Association of Regulatory Utility Commissioners and the National Association of Pipeline Safety Representatives.

And the third panel will include representatives from the pipeline industry and pipeline safety advocacy groups. We are appreciative and grateful for all of your views on the topic of pipeline safety.

Congress, as you know, passed the Pipeline Safety Improvement Act of 2002 to improve pipeline safety and security practices, and to provide

Federal oversight of pipeline operator security programs. That is due for reauthorization at the end of this year, and the purpose of this hearing really is to see how successful or how unsuccessful the implementation of that Act has been with an eye toward legislation reauthorizing the Act.

And again, I look forward to hearing from all of you on the progress you have made and are helping us to make, and your recommendations as the committee goes forward. I really appreciate your time.

[The prepared statement of Hon. Ralph M. Hall follows:]

PREPARED STATEMENT OF THE HON. RALPH M. HALL, CHAIRMAN, SUBCOMMITTEE ON ENERGY AND AIR QUALITY

I want to begin by thanking our many witnesses for testifying before the Subcommittee today. Protecting the safety of our pipeline system requires the comprehensive and coordinated effort of several federal and state agencies, industry and pipeline safety advocacy groups.

To this end, the hearing will consist of three panels of witnesses. The first panel will consist of representatives from the Department of Transportation's Pipeline and Hazardous Materials Administration and Office of Inspector General, the National Transportation Safety Board and the Government Accountability Office. The second panel will consist of representatives from the National Association of Regulatory Utility Commissioners and the National Association of Pipeline Safety Representatives. The third panel will include representatives from the pipeline industry and pipeline safety advocacy groups. We are appreciative and grateful for your all of your views on the topic of pipeline safety.

In the 107th Congress passed Pipeline Safety Improvement Act of 2002 to improve pipeline safety and security practices and to provide federal oversight of pipeline operator security programs. That Act is due for reauthorization at the end of this year. The purpose of this hearing is to see how successful or unsuccessful implementation of that Act has been with an eye towards legislation reauthorizing the Act.

Again, I also look forward to hearing from you all on the progresses you've made and your recommendations as the Committee goes forward legislatively.

MR. HALL. At this time, we will recognize Mr. Boucher.

MR. BOUCHER. Thank you very much, Mr. Chairman.

I want to commend you for convening today's hearing on the timely question of pipeline safety.

In 2002, this Committee enacted, on a bipartisan basis, the Pipeline Safety Improvement Act. And now, as we near the time for reauthorization of that measure, it is appropriate that we hear from interested parties concerning their views about the appropriateness and effectiveness of the 2002 legislation and receive suggestions for improvements that can be made to the Nation's pipeline safety laws.

The witnesses that we have before us today offer a broad range of expertise, and I look forward to hearing from them. I am particularly pleased that we have a witness from my home State of Virginia who will provide testimony on Virginia's highly successful program to prevent excavation damage to natural gas pipelines. Since implementation of

Virginia's program, our State has experienced a dramatic reduction in excavation damage. I look forward to hearing from the witnesses about the manner in which this program operates, perhaps some operational detail would be helpful for us, and also their view of the program successes, and perhaps most importantly, their recommendations as to whether or not the Virginia experience could serve as a model for what other States might do in order to address their own problems with excavation damage to natural gas pipelines.

In addition, I hope that our witnesses will address a number of matters that are of further interest. I was pleased that the 2002 Act included a section authorizing technical assistance grants for local communities. However, it is my understanding that no grants have been awarded under this program since its inception. I am continually of the view that providing assistance to local communities for technical assistance on pipeline issues is important, and I have been disappointed that the program has not functioned as we intended it to function. Perhaps our witnesses can comment on the reasons that technical assistance grants to communities have not been awarded to date and make suggestions to us for ways that we can structure this program more appropriately to assure that its objectives are met.

During the hearing before this subcommittee two years ago, a Department of Transportation official testified that the Department planned to develop an integrity management plan for natural gas distribution lines. The distribution lines comprise approximately 85 percent of all of the natural gas pipelines in the country. But at that time, the idea of a comprehensive integrity management plan for distribution lines was merely a recommendation. Now the Office of Pipeline Safety is moving ahead with the establishment of an integrity management plan for these distribution lines. It is my understanding that a report on integrity management for gas distribution has been produced through a consultative process involving a wide range of stakeholders, including the Federal and local officials directly affected, industry experts, and safety advocates, and that the Office of Pipeline Safety expects to publish a distribution integrity management early in 2007. That is good news, indeed. And this effort marks the first comprehensive and consensus-based attempt to develop an integrity management plan for natural gas distribution lines. And I commend the effort and look forward to learning more about the progress of the development of this plan.

There are many areas that our witnesses could usefully address. For example, a recent failure on a subsequent crude oil leak from a low-pressure transmission line in Alaska highlights, I think, the need for a regulation of low-pressure pipelines. And I understand that OPS is now developing regulations in order to cover those lines. I applaud that approach.

I expect that some of our witnesses will address the requirement for periodic inspection of the 10-year baseline and the 7-year inspections that are performed on a re-inspection basis that were mandated in the 2002 legislation. The Act also requires GAO to complete a study with regard to the appropriateness of these particular timelines, the 10-year baseline and the 7-year periodic inspections. While that report will not be completed until the fall, we would welcome today, or at any time between now and then, any preliminary findings from the report that witnesses would care to present to us.

Having said that, I would caution that I think we need to allow time for the GAO to complete its work and make final recommendations before reaching any judgments about possible changes to the timing of these inspections.

Finally, I would like to hear the general opinions of our witnesses on the successes, generally speaking, and the problems that have been presented through implementation of the 2002 Act. It is my perception that the consensus Act we passed in 2002 has produced positive results with an increased emphasis on safety and accident prevention both by the agencies of enforcement and by the industry.

The views of our witnesses on all of these matters would be most welcome, and I look forward to their presentations.

And I thank you, Mr. Chairman, for your indulgence during this somewhat lengthy opening statement.

MR. HALL. I thank the gentleman. The Chair recognizes, for 3 minutes, the gentleman from Pennsylvania, Mr. Murphy.

MR. MURPHY. Thank you, Mr. Chairman, for holding this important hearing. And I share the views expressed of using this as an opportunity to see what we can do to assure pipeline safety as we look at what is involved in this Act.

But I want to draw attention to one particular issue here that occurred in my district, the 18th District in Pennsylvania.

On March 16, 2005, two teenagers in my district, while coming home from school, walked past utility workers who had ruptured a natural gas pipeline. Apparently, the gas had been seeping for some time, and they followed the local rules to notify the community via fax to an office that was not manned at the time. As the gas continued to seep into their home, and let me show you a picture of their house before.

[Slide.]

As the gas continued to seep into their home, this house the children walked into with the smell of natural gas in the air.

[Slide.]

While one child was up in the upper left part of the house watching TV, another child was downstairs, could you show the next picture, the house, in seconds, was reduced to this.

Now unfortunately, many States do not have uniform standards in terms of how to notify local officials when there is a rupture in a pipeline, and this is not an interstate transmission line, this is a neighborhood line. However, there is a hodgepodge of rules, and my question is if we need to have uniform nationwide standards or, at the very least, require each State to have a workable notification system, such as calling 911, or some other number, where there is a person there to do something to secure the neighborhood, notify the gas company, and clear the area all at once.

We, unfortunately, do not have unified rules such as that, and one of the things I am hoping to hear from people testifying today is what we can do to prevent these. Now we also recognize that there are problems with regard to even making sure we follow the rules notifying before someone digs, making sure we have qualified people doing the digging where there are gas pipelines around. And we also should have some rules with regard to increased penalties when people do not follow those notification procedures. But those are the two ends: the preparation and the fine at the end.

What I am concerned about is what happens in the middle. Much like healthcare, we may be able to prevent illnesses, and at the end, if someone has an error, we may be able to find them or have some other lawsuits to deal with that. But in the middle process, we do have a confusing array of laws around this Nation and within States. And one of the things that I am hoping to get out of this hearing is a sense from the experts involved in these fields of pipeline safety of what we can do to make sure that young children like Mark and Chelsea, who, unfortunately, were severely burned in this incident, do not happen again.

For all of these reasons, I have introduced H.R. 2958, which would establish some notification standards for any excavator, construction worker, and anyone else who calls or becomes aware of damage to a pipeline. And I am hoping that that is one of the issues that we can resolve so that situations like this, dangerous situations, do not occur again. And luckily, Mark and Chelsea are better now with some scars. Their family is traumatized from this, and they are moving on to a new home. But when you look at that situation, I hope it helps motivate Members of Congress to understand the hundreds of people who have died in pipeline accidents, and the thousands of incidents that occur. It is time we work on finding ways to prevent this from happening again.

Thank you, Mr. Chairman.

MR. HALL. I thank you for a good opening statement.

I recognize the gentleman from Texas, Mr. Green, for three minutes.

MR. GREEN. Thank you, Mr. Chairman and Ranking Member Boucher for putting together such a very solid group of witnesses for today's hearing on a very important issue. Obviously to Pennsylvania, but also to Texas and the district I represent, pipeline safety. I would like to note that pipelines are the safest and most efficient form of transportation, any way you measure it, especially for energy products like natural gas, crude oil, fuel, or propane. It is much better for those things to be in a quality steel pipe in the ground and not on trucks on the roads, and I think we should promote pipelines when they can be safe and efficient.

To do that, we must ensure pipelines remain the safest form of transportation with continuing inspections and better technology. Every pipeline in a high-consequence population area must be inspected, and many other less populated areas will also be inspected by 2012, 10 years after the Act. But if a pipeline runs in your neighborhood, like they do in many parts of our district, it should be inspected and re-inspected. Our legislation 5 years ago made some major changes and improvements which are in the process of making the ten-year baseline safety goals set up by that Act. I am interested to hear the testimony from our panels about how the ten-year baseline assessment we set four years ago is going and what plans are going on for the ongoing reassessment phase.

And again, thank you, Mr. Chairman and Ranking Member, and I yield back my time.

MR. HALL. I thank the gentleman.

The Chair recognizes Mrs. Wilson, the gentlelady from New Mexico, for 3 minutes.

MRS. WILSON. Thank you, Mr. Chairman, and thank you for this hearing.

In August of 2000, an explosion in an El Paso Natural Gas Company pipeline near Carlsbad killed 12 people, 2 extended families, including a 6-month-old infant. The explosion of a 30-inch, 50-year-old natural gas pipeline left a crater that was 86 feet long, 36 feet wide, and 20 feet deep. It was the natural gas pipeline explosion that was the most serious one in terms of fatalities in the past 25 years.

In New Mexico, in addition to our interstate pipelines, we have 13,000 miles of intrastate natural gas pipelines. In fact, 10 percent of the natural gas consumed in the Nation today comes from the State of New Mexico. A third of California's natural gas comes from the State of New Mexico, most of it from the Four Corners Region. Thirteen thousand miles of natural gas pipelines crisscrossing our State to supply the Nation with natural gas. That is enough to go from Albuquerque, New Mexico to Bombay, India.

Since 2003, we have had one fatality and four injuries because of pipeline safety incidents. While we have made progress, that is one fatality and four injuries too many. Pipelines are near people. They run through neighborhoods, near schools, and hospitals. And for those of us who live in States that produce the natural gas that the Nation needs, these are major issues.

We have to keep these pipelines safe. And I continue to believe that our pipeline industry continues to use old technology with respect to making sure pipelines are as safe as they can be, and we need to make significant improvements in the research and development to bring pipeline safety into the 21st century.

Mr. Chairman, thank you very much for holding this hearing.

MR. HALL. I thank the gentlelady.

I recognize Mr. Otter, the gentleman from Idaho, for 3 minutes.

MR. OTTER. Mr. Chairman, I want to defer so we can get on with the witnesses' testimony.

MR. HALL. That is very kind and generous of you.

We will go to the witnesses at this time.

[Additional statements submitted for the record follow:]

PREPARED STATEMENT OF THE HON. JOE BARTON, CHAIRMAN, COMMITTEE ON ENERGY AND COMMERCE

Chairman Hall, thank you for holding this hearing today. I want to also thank our many witnesses for testifying before the Subcommittee today. We are appreciative and grateful for your analysis and views on the topic of pipeline safety.

Nearly half a million miles of crude oil, petroleum product and natural gas transmission pipeline crisscross the United States. These pipelines are integral to U.S. energy supply and have vital links to other critical infrastructure, such as power plants, airports, and military bases.

The best and most effective way to bring down fuel prices is to increase supply, and more oil will require more pipelines. While we have ships, trucks and railroads, pipelines are the arteries of the nation. They are just the most effective way to transport oil, natural gas and gasoline.

Last fall, the House passed the GAS Act to address concerns about high gasoline prices by easing siting and permitting restrictions for refineries and pipelines. I intend to make pipeline projects a reality. The critics want to build problems instead of pipelines, but that's not an energy policy. It's a policy to raise gasoline prices on working people.

Of course, protecting the safety of our existing pipeline system is the most important thing we can do to secure our existing supply and to safeguard our citizens. This requires the comprehensive and coordinated effort of several federal and state agencies, industry and pipeline safety advocacy groups. However, when it is operating at its very best, you don't know even it's there.

There has been recent attention in the press on pipeline safety following the BP pipeline leak in Alaska. I know there have been Department of Transportation investigations since the Department issued its Corrective Action Order. I recognize that the investigation is ongoing and look forward to a better understanding of the causes of this leak as the investigation continues.

The 107th Congress passed the bipartisan Pipeline Safety Improvement Act of 2002 to improve pipeline safety and security practices and to provide federal oversight of pipeline operator security programs. A centerpiece to the Act is the requirement it places on oil and natural gas pipeline operators to prepare and implement an integrity management program. I also look forward to hearing from you all on the progress and results of this program.

Later, this Subcommittee will turn to a possible reauthorization of pipeline safety laws. Chairman Hall and I are ready to work with Congressman Dingell and Boucher and all other Members of the Subcommittee on a successful bill.

PREPARED STATEMENT OF THE HON. MICHAEL BURGESS, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF TEXAS

Thank you, Mr. Chairman for holding this important hearing.

When our constituents think of the movement of products and goods across the country -- most of them think about large trucks on the highway carrying everything from ice cream to new cars.

Some think of the railroads and others think about the barges that traverse the Mississippi. But few think of the interstate transmission pipelines that transport huge volumes of crude oil, refined products including gasoline and natural gas; until something goes wrong.

In 2000, three people died in a natural gas distribution pipeline explosion in Garland, Texas, which is just east of my congressional district.

Although this particular pipeline does not fall under federal jurisdiction, it shows just how high the stakes can be and why it is so critical that we have a robust federal pipeline safety program.

Fortunately, these types of accidents do not occur frequently. Oil pipelines reported an average of 1.4 deaths per year from 2000 to 2004; gas pipelines reported an average of 17.0 deaths per year during the same period.

Congress last updated the federal pipeline safety law in 2002. Among other things, the bill required operators of regulated gas pipelines in densely populated areas to conduct risk analysis and periodic inspections, and to strengthen public education regarding pipeline safety.

One of the best ways that we can reduce the risk of harm to the general public is through education. The Danielle Dawn Smalley Foundation, in Chairman Hall's district, is a non-profit organization that conducts these types of education programs for the general public as well as for first responders, including the City of Fort Worth Fire Department which will participate in the program later this year.

In conclusion, Mr. Chairman, while the risk of harm from a pipeline accident is far less than driving on I-35 West, we should always strive to do better.

I am looking forward to hearing from our witnesses today about how they view the changes made in 2002 as well as their suggestions for us as we move forward with reauthorization during the 109th Congress.

PREPARED STATEMENT OF THE HON. JOHN D. DINGELL, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF MICHIGAN

Mr. Chairman, I commend both you and Chairman Barton for holding this very important hearing and for working with us cooperatively to assemble the panels before us today.

Pipeline safety is an immensely important but little-followed energy issue. We are all aware of the catastrophic damage that can occur to life, property, and the environment when a line fails. We all remember the horrible tragedies of Bellingham, Washington, and Carlsbad, New Mexico, that resulted in the loss of life. We learned last summer after Hurricane Katrina the supply problems that can occur when pipeline integrity is compromised. This concern arose again, albeit on a smaller scale, with the breach of the Plantation pipeline outside of Richmond, Virginia, which resulted in the spill of over 27,000 gallons of jet fuel – a precious commodity to the struggling airline industry.

The good news is that in recent years the Federal Government's approach to pipeline safety seems to be improving. The Pipeline Safety Improvement Act of 2002 deserves a good portion of the credit for those improvements. Through baseline assessments, operators of natural gas transmission lines have been able to identify and repair anomalies before they result in catastrophic accidents; the Office of Pipeline Safety has made tremendous progress in meeting mandates of the Act and responding to recommendations of the National Transportation Safety Board (NTSB) and the Department of Transportation Inspector General; one-call notification programs to prevent excavation damage have been strengthened and are continuing to improve around the country.

The basic structure of the 2002 Act is a sound one that we should amend only in those few areas that it can be improved upon. With this in mind I hope that our witnesses can inform us on a number of issues including means to further strengthen the enforcement approach of the Office of Pipeline Safety, the need to take more action to prevent excavation damage, and the merits of an integrity management program for America's local distribution gas companies.

Challenges remain, however. I must note that events have a way of focusing Congressional attention and I hope that we will explore the issues surrounding the recent spill of over 200,000 gallons of crude oil on Alaska's North Slope. Unfortunately the line that failed was exempt, by regulation, from Office of Pipeline Safety oversight. It seems that because the line was operating at low pressure it was assumed that the risk was also low. That assumption has been turned on its head. We need to find out how many of these lines exist and how they may be regulated. Whether you are a defender of the Alaskan environment, a proponent of hydrocarbon production in Alaska, or both, this spill was bad news for everyone. I hope the Subcommittee will seriously examine this issue. I have attached correspondence to my statement that details some of the information that our investigative efforts have uncovered thus far and I ask that it be included in the record.

Finally, Mr. Chairman, I want to reiterate that the Pipeline Safety Improvement Act of 2002 was a good piece of legislation of which we may all be proud. It was the result of much hard work and enjoyed the support of industry, safety advocates, environmentalists, and the States. It was the result of a bipartisan process. I hope that as we begin to look at its reauthorization we keep its origins in mind and attempt to follow a similar path. I thank you and look forward to hearing from our witnesses.

PREPARED STATEMENT OF THE HON. CHARLES A. GONZALEZ, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF TEXAS

Mr. Chairman,

I would like to thank you for convening this important hearing on pipeline safety today. As the supply and demand cycle for energy in America continues to tighten, maintaining the safe and efficient transmission of natural gas is vitally important to our nation's economic and domestic security. I look forward to receiving an update from the witnesses before us today on the progress of implementing the *Pipeline Safety Improvement Act of 2002,* and whether or not changes need to be made as we consider reauthorizing this important legislation. I appreciate the special challenges presented by ensuring the integrity and safety of the nation's pipeline systems, while still preserving the uninterrupted delivery of energy to markets in a supply tight environment. I welcome the witnesses to address whether we have built enough flexibility into the process to allow for needed inspections to take place concurrently with meeting the delivery requirements of our citizens and industries.

I am especially interested in hearing the thoughts of the panel regarding the progress of the initial inspections of all high consequence pipeline as required by the 2002 Act. Completing these baseline inspections in a timely manner is crucial to ensuring reliable transmission of natural gas, and meeting the safety mandate set forth by Congress. In addition, I am eager to hear from the witnesses on the issue of the re-inspection of pipeline and the interval at which these re-inspections should occur. I would like to hear the panel address whether the current seven year re-inspection mandate is reasonable. In particular I would like to know their views as to whether we should transition to a standard that prioritizes resources on the highest stress pipelines. In other words, would an approach that emphasized inspecting higher consequence pipe more often and lower consequence pipe less often be more or less effective at identifying and correcting safety risks. Finally, I would also like to hear whether the panels feels that requiring re-inspections to begin after seven years, which is before the baseline inspections have been completed, will result in extra segments of pipeline being removed from service and what impact that might have on the supply chain in certain regions of the country.

Again, I thank the Chairman for calling attention to these issues with vast national and economic security implications. I look forward to receiving today's testimony.

MR. HALL. We have Ms. Stacey Gerard, Acting Administrator and Chief Safety Officer, Pipeline Hazardous Materials Administration. I recognize you. Just summarize for 5 minutes or thereabouts, or as close as you can.

And thank you. We will recognize you at this time.

STATEMENTS OF STACEY L. GERARD, ACTING ADMINISTRATOR/CHIEF SAFETY OFFICER, PIPELINE AND HAZARDOUS MATERIALS ADMINISTRATION, U.S. DEPARTMENT OF TRANSPORTATION; THEODORE ALVES, PRINCIPAL ASSISTANT INSPECTOR GENERAL FOR AUDIT AND EVALUATION, OFFICE OF GENERAL INSPECTOR, U.S. DEPARTMENT OF TRANSPORTATION; ROBERT CHIPKEVICH, DIRECTOR, OFFICE OF RAILROAD, PIPELINE, AND HAZARDOUS MATERIALS INVESTIGATION, NATIONAL TRANSPORTATION SAFETY BOARD; AND KATHERINE SIGGERUD, DIRECTOR, PHYSICAL INFRASTRUCTURE ISSUES, U.S. GOVERNMENT ACCOUNTABILITY OFFICE

MS. GERARD. Thank you, Mr. Chairman, distinguished members of the subcommittee. I appreciate the opportunity to appear today to discuss U.S. DOT's Pipeline and Hazardous Material Safety Administration's efforts to improve the safety of America's pipelines.

Our Acting Administrator, Brigham McCown, regrets that he can’t be here today, because he is on previously-scheduled military duty as a reserve officer in the U.S. Navy.

We understand the subcommittee’s concern surrounding the safety of your constituents and all Americans who live, work, and conduct their daily routines near pipelines. Our agency has taken actions to achieve results, including reducing the number of pipeline incidences of severe consequences to people.

Under Secretary Mineta’s leadership, PHMSA has succeeded in addressing every mandate of the Pipeline Safety Act of 2002. We have eliminated most of the 12-year backlog of past mandates of recommendations from the Congress, the MTSB, the DOT Inspector General, and the General Accountability Office. Just last month, we published the final rule to define and regulate natural gas gathering lines.

Now we are working on our last outstanding mandate, protecting unusually sensitive areas from risks posed by rural liquid gathering lines and low-stress transmission lines. We will be holding a public workshop in June to review our concepts to improve protection, how to seek a consensus among stakeholders so we can expedite this rule. The June workshop will address the need for a maintenance, testing, leak detection, operator qualification, marking, buffer zones, and other topics. This rule is relevant to the low-stress transmission pipeline that failed recently on the north slope of Alaska. We issued a corrective action order to protect the people and the environment of Alaska. We are working hard to make operations safer and are working closely with Alaskan State agencies.

We have taken advantage of higher penalty authority by imposing, and collecting, larger penalties. Compared to 2003, the first year when higher penalty authority was available, we doubled the civil penalties proposed in 2004 and tripled them in 2005. For calendar year 2005, the proposed penalties amounted to over $4 million.

Additionally, from 2003 to 2005, we closed 56 percent of the penalty cases and collect 94 percent of the total penalties proposed. We have reinforced our partnerships with State pipeline safety agencies through a policy collaboration, better training, shared data, and more frequent communication. Pipeline safety depends on States overseeing roughly 90 percent of the infrastructure. Since appearing last before this committee in 2004, we are now enforcing regulation of the integrity management programs for both hazardous liquid and natural gas transmission operators. The interstate partners have conducted comprehensive inspectors. Liquid operators are assessing and repairing nearly 80 percent of the Nation’s hazardous liquid pipelines and gas operators are replacing nearly 60 percent of their transmission pipelines. About 82 percent of the most sensitive areas have already been assessed.

In June of 2005, the Bush Administration sent the Congress our plan to strengthen the safety of distribution pipelines through use of integrity management principles, and a rulemaking is well along the way.

We are also raising the quality of education operators provide. First, we oversaw operator self assessments required by the law and determined considerable improvement was needed. We called for a new consensus standard for public education, and stakeholders responded by creating one that significantly raised the bar. We adopted it in regulation. PHMSA has invested over $5 million since the passage of the Pipeline Safety Act to bringing meaningful information to the public regarding pipeline operator performance.

Working with the Common Ground Alliance, we have led many stakeholders to share responsibility for our number one priority, damage prevention. We thank the CGA and its volunteers for their partnership and leadership and helping us fight the war on damaged underground facilities. They are doing a great job on that and to implement 811. It provides one action all Americans can take to improve safety.

We have been building a new, more comprehensive, and improved approach to pipeline safety. We are improving pipeline performance by managing risk, sharing responsibility, and providing effective stewardship. This plan is consistent with the Pipeline Safety Act and leaves no stone unturned in identifying and addressing pipeline risk.

We recognize there is always room for improvement and believe there is more work to be done. We look forward to continuing to work with all of you.

Thanks very much.

[The prepared statement of Stacey L. Gerard follows:]

PREPARED STATEMENT OF STACEY L. GERARD, ACTING ADMINISTRATOR/CHIEF SAFETY OFFICER, PIPELINE AND HAZARDOUS MATERIALS ADMINISTRATION, U.S. DEPARTMENT OF TRANSPORTATION

Good morning, Mr. Chairman. Thank you for inviting the Department to testify today before your Subcommittee to provide you and the other members an update on the successes of the Department's pipeline safety program. Our Acting Administrator Brigham McCown regrets he cannot be here today as he is on previously scheduled annual military duty as a reserve officer in the U.S. Navy. I am Stacey Gerard. I currently serve in dual roles as the Pipeline and Hazardous Materials Safety Administration's (PHMSA) Acting Assistant Administrator/Chief Safety Officer as well as the agency's Associate Administrator for Pipeline Safety.

This opportunity to discuss our progress in improving the safety and reliability of the Nation's pipeline infrastructure is welcome. The 2.3 million miles of natural gas and hazardous liquid pipelines carry nearly two-thirds of the energy consumed by our Nation and as such, it is easy to see why our pipelines are in fact, our energy highways. It is also important for me to stress that as a mode of transportation, our pipelines remain the safest and most efficient way to transport the enormous quantities of natural gas and hazardous liquids America uses each day.

We greatly appreciate this Subcommittee's attention to our efforts in advancing pipeline safety. We are achieving results – pipeline accidents with severe consequences to people are trending steadily downward. There has been an increase in the total of all reported accidents in the recent past. Although we are watching these numbers closely, I can report that we believe this data reflects normal variations in year-to-year reporting, and also reflects damage caused by last year's hurricanes. Higher fuel prices also mean that smaller spills now qualify for reporting under the property damage criteria.

Under Secretary Mineta's leadership, PHMSA has succeeded in achieving every mandate set forth in the Pipeline Safety Improvement Act (PSIA) of 2002, and the agency has done so in a timely manner. This testimony today will provide an update on the progress report given 18 months ago.

Demographic changes taking place in our country require us to be increasingly vigilant. Urbanization of previously rural areas is placing people closer to pipelines. Expansion and development also means more construction activity near pipelines. It should come as no surprise therefore that third party excavation damage is a leading cause of pipeline accidents.

Encroachment on areas containing pipelines increases the potential for pipeline accidents, which although infrequent, can have tragic consequences. We have stepped up our efforts to address third party damage because of greater congestion in our underground infrastructure and the potential to save lives. Managing the risk to pipelines is more difficult because the underground is increasingly crowded with the installation of new fiber optics and telecommunications infrastructure central to our way of life.

Our record as a regulator and overseer of public safety is important to us. Safety is, and remains the Administration's top priority when it comes to regulating the pipeline industry. In addition to addressing the many mandates of the PSIA, PHMSA has eliminated most of a 12-year backlog of outstanding mandates and recommendations from the Congress, the National Transportation Safety Board (NTSB), the Department of Transportation (DOT) Inspector General, and the Government Accountability Office (GAO). Over the past five years, the agency has responded positively to 46 NTSB safety recommendations and is working to close the three recommendations remaining from the pre-2002 environment. The GAO recently closed eight pipeline safety recommendations─ six in enforcement, and two in research and development.

Just last month, we published the final rule to define and regulate natural gas gathering lines.

Through rulemaking we are actively addressing our last outstanding mandate, protecting unusually sensitive areas from risks posed by rural liquid gathering lines and low stress transmission pipelines. This rule is relevant to the low stress transmission pipeline that failed recently on the North Slope of Alaska. We issued a corrective action order soon after to ensure safety and environmental protection of that and two similar lines nearby. We are making good progress with the remediation of the failed line and are working closely with Alaska State agencies. We will be holding a public workshop in June to review our concepts to improve protections and address other important issues. The June workshop will focus on low stress lines and how they can be improved through leak detection, operator qualification, maintenance, defining applicability criteria, and buffer zones.

Stronger oversight has been an important strategy in strengthening pipeline safety. In the past 12 years, the agency has added 60 additional inspectors to PHMSA's pipeline safety staff, up from 28 inspectors in 1994. PHMSA's state agency partners employ over 400 additional inspectors who oversee 90 percent of the infrastructure and contribute 50 percent of the total costs. This Federal-State partnership is crucial to the agency's success.

PHMSA is fulfilling its plan to improve the safety, reliability, and environmental performance of the Nation's energy transportation pipeline network. Our plan includes a multi-phase strategy which leaves no stone unturned in identifying and addressing pipeline risks. To manage the risks inherent in pipeline transportation, PHMSA has been building a new, more comprehensive and informed approach to pipeline safety consistent with the PSIA.

This plan, discussed 18 months ago, is based on improving pipeline performance by: (1) managing risk; (2) sharing responsibility; and (3) providing effective stewardship.

I. We Are Implementing A Plan To Manage Risk

We have raised the bar on safety. By collecting and using better information about pipelines, today we know more about pipelines, the world they traverse, and the consequences of a pipeline failure.

By strengthening our ability to better collect and analyze data, we can better characterize safety issues and highlight pipeline operators with performance concerns. We have also strengthened our regulations and oversight to respond to problems.

1. Higher Standards

We have raised the standards for pipeline safety across the board through requirements for integrity management, operator qualification, public education and 19 other regulations, and incorporated 68 new national consensus safety standards.

2. Better States' Partnership

We have strengthened our partnerships with State pipeline safety agencies through increased policy collaboration, better training, shared databases, and a distributed information network to facilitate communication. In partnership with our State inspectors, we are working hard to deliver better oversight in accordance with higher standards.

3. Stronger Enforcement

We have taken advantage of higher penalty authority and have institutionalized a tough-but-fair approach to enforcement. We are imposing and collecting larger penalties, while guiding pipeline operators to enhance higher performance. We also coordinated much more effectively with other Federal agencies, including the Department of Justice and the Environmental Protection Agency. We have identified several performance measures to track the impact of our enforcement efforts, such as the severity of inspection findings. Compared to 2003, the first year when higher penalty authority was available, we doubled the civil penalties proposed in 2004 and tripled them in 2005. For calendar year 2005, the proposed penalties amounted to over $4,000,000. For the period from calendar year 2003 to 2005, PHMSA has closed 56 percent of the penalty cases and collected 94 percent of penalties we proposed.

4. Better Technology

To improve the technology available to assess and repair pipelines, we have invested over $22 million in technology research and development since 2002 and leveraged an additional $26 million in investments from the private sector. These investments have jump-started more than 80 projects across the country and have already generated eight new patent applications.

5. Greater Resources

DOT has requested, and the Congress has appropriated, 24.5 percent more resources since 2002 to help implement the plan to improve pipeline safety.

II. Sharing Responsibility ─ Preparing Partners

Advancing pipeline safety in the face of growing construction in our communities is a big task and we need help to succeed.

We have identified clear roles for others at the Federal, State, and local levels of government and citizens to help us and they are responding. These roles range from environmental and emergency planning to better zoning and management of land use near pipelines, to helping prevent damage and permitting repairs to pipelines, to citizens taking safety actions to protect themselves.

Our pipeline safety communications program provides crucial knowledge about the pipeline system to our various stakeholders, including our citizens, which enables them to share responsibility for continuously improving safety. PHMSA has invested over $5 million since the passage of the PSIA to bring meaningful information to the public regarding pipeline operator performance. We recognize that by "going local," we are better able to affect pipeline safety where it matters most─ in the neighborhoods where our Nation's citizens work, play and live.

III. Effective Stewardship

Our role has evolved in response to a dynamic environment. The energy pipeline infrastructure in the United States represents a $31 billion investment. These energy highways also transport the essential fuels needed to produce a myriad of goods and services in our economy and make millions of jobs possible.

The agency's relationship with the industry it regulates has proved vital in the timely understanding of operational problems caused by natural disasters and our ability to rapidly respond. During Hurricanes Katrina and Rita, PHMSA moved quickly to assess interruptions in energy product transportation and facilitated rapid restoration of supply. By working with our sister agencies and pipeline operators, DOT was responsible for returning our pipeline infrastructure to full operating capability within days of each storm's passing.

From our vantage point as safety regulators over the entire industry, we have a unique knowledge of this infrastructure. By what we know, we can inform other agencies to help with energy capacity planning as well as economic and security considerations.

IV. Responding to the Pipeline Safety Improvement Act of 2002

The Congress recognized the critical importance of pipelines to our Nation's vitality when it passed the Pipeline Safety Improvement Act of 2002. Under Secretary Mineta's leadership, PHMSA has aggressively responded to these new mandates.

1. Integrity Management

Since last appearing before this Committee in June 2004, PHMSA is now enforcing regulation of integrity management programs for both hazardous liquid and natural gas transmission operators. PHMSA and its State partners have completed comprehensive inspections of large hazardous liquid operators who are assessing and repairing nearly 80 percent of the Nation's hazardous liquid pipelines, resulting in the elimination of over 20,000 time sensitive pipeline defects. Our hazardous liquid integrity inspections address, among other safety issues, the adequacy of placement of emergency flow restricting devices and the adequacy of the leak detection systems. We worked with 46 percent of operators inspected to improve their preventive and mitigation measures.

PHMSA has now completed 13 percent of gas transmission integrity management inspections, providing supplemental protections for approximately two-thirds of American communities living along natural gas pipelines. We expect eventually that nearly 60 percent of the natural gas transmission pipeline mileage will be similarly assessed and repaired.

In June 2005, the Administration submitted our plan to Congress to strengthen the safety of gas distribution pipeline systems through use of integrity management principles. We work closely with the State Utility Commissions who have jurisdiction over distribution systems and the ultimate authority to decide what additional protections to require and what costs to pass on to consumers. We are following the guidance provided in the February 16, 2005 National Association of Regulatory Utility Commissioners' "Resolution on Distribution Integrity Management" in implementing this safety plan which urges a performance based approach that leaves states flexibility. PHMSA began work with the Gas Piping Technology Committee to develop consensus guidance to accompany the agency rulemaking that is underway.

2. Operator Qualification

Our regulations require operators of gas and hazardous liquid pipelines to conduct programs to qualify individuals who perform certain safety-related tasks on pipelines. In early 2003, we developed a standard to evaluate the adequacy of operators' programs, as required by the PSIA. We also issued a Direct Final Rule that codifies the new mandated requirements concerning personnel training, notice of program changes, government review and verification of programs, and use of on-the-job performance as a qualification method.

We completed all reviews of interstate operators' qualification programs and met the 2005 statutory deadline. States have made similar progress. Our report to the Congress is due December 2006. We held two public meetings to seek more comprehensive information from states, the public and the pipeline industry to produce an informative final product.

We are considering some additional improvements in our regulations. We plan to incorporate in our enforcement approach improved consensus standards for the qualification of pipeline operators for safety critical functions.

As required by the PSIA, we conducted a controller certification pilot program to evaluate how best to further assure pipeline controllers have and maintain adequate qualification for their required job tasks. We reviewed information on training and qualification programs from a variety of resources, including programs of other industries, the NTSB, operators, trade associations, public interest groups, system vendors, and simulator specialists. We have completed our assessment and will hold a public workshop in June to share our findings. This workshop will focus on alarms, shift change procedures, roles controllers play, fatigue, recognition of abnormal events, and validation of adequacy of control processes.

3. Public Education and Mapping

Working with others, we are raising the quality of public education operators provide, as well as what we provide. First we oversaw operators' self assessments required in the PSIA and determined considerable improvement was needed. We called for a new consensus standard for public education and stakeholders responded by creating one that significantly raised the bar. The NTSB acted to close all its recommendations on public education. We conducted four nationwide, webcast public meetings on this standard to build effective public awareness programs. Currently, we are developing a clearinghouse to review and evaluate the adequacy and effectiveness of more than 2,200 public safety and education programs established locally by the pipeline industry.

We have enlisted State fire marshals to help bring information and guidance to communities across America and build an understanding of pipeline safety and first responder needs. In less than 15 months, we made great strides in advancing our fire service training curriculum. We have provided training to approximately 5,000 trainers in 31 States and distributed over 13,000 textbooks, 5,000 instructor guides and 6,000 training videos. The first-of-its-kind pipeline accident response training and public education program for first responders will help pipeline operators to identify high consequence areas in communities and provide an understanding of liquefied natural gas operations.

We are improving our efforts to reach the public by preparing local officials to be public education resources within communities and providing additional resources for citizens to learn how they can protect themselves and pipelines. Our community assistance and technical services staff provide information to citizens and advise local officials to guide their decisions about local land use. We also utilize the efficiency of the World Wide Web to give citizens and other stakeholders instant access to community specific pipeline information with our newly established stakeholder communications website.

We completed the base structure of the National Pipeline Mapping System in 2003, and keep it up to date with improvements. We recently made the system available for public web searches on contact information of pipeline companies and made other web improvements to help the public access general information on pipelines and operator performance. We provide more sensitive mapping information to Federal, State and local governments through a password-protected application. This information is restricted by jurisdiction and cannot be released outside of the requesting agency.

Working with the pipeline industry and State agencies, we annually hold about 15 public meetings per year to acquaint citizens and public officials with essential safety information to make informed decisions about living safely with and minimizing damage to pipelines.

4. Damage Prevention

Helping communities know how they can live safely with pipelines by preventing damage to pipelines is a very important goal. We cannot succeed without enlisting the help of State and local officials and the full range of public safety stakeholders who share an interest in protecting all underground infrastructure.

We work with the Common Ground Alliance (CGA) on all damage prevention efforts, leading many stakeholders to share responsibility for damage prevention. We are now planning to implement the most important new tool in our assault on third-party damage to pipelines, three-digit dialing, required in the PSIA. The Federal Communications Commission responded favorably to our request for a single three-digit number usable for “one call” anywhere in the U.S. Three-digit dialing of “811” provides a single uniform action that all Americans can take to improve safety. Since 2002, our partnership with the CGA has helped us address nine NTSB recommendations in preventing damage to pipelines.

We also worked with CGA to create 44 new regional CGAs to help communities implement damage prevention best practices across all underground facilities. These alliances provide synergy in the “underground” among other utilities, railroads, insurance companies, public works and other municipal organizations, to implement best safety actions. The CGA highlights best practices of leading States such as Minnesota, Virginia, Connecticut, Georgia, and Massachusetts in identifying and enforcing the elements of an effective damage prevention program for other States to follow. These States’ enforcement against all who violate their laws led to a 50 percent decrease in damages in just a few years. Strengthening enforcement is one of many important best practices we promote through the CGA and with our state partners and we believe all states can achieve similar results.

5. Research and Development

Over the past three years, PHMSA has built a research and development (R&D) program that has funded 80 projects at a cumulative expense of nearly $50 million to address better diagnostic tools, testing of unpiggable pipes, stronger materials, improved pipeline locating and mapping, prevention of outside force damage, and leak detection.

We are focused on near-term technology development needs. We support technology demonstrations such as remote sensing of gas leaks and internal inspection of unpiggable pipes.

We are maximizing the return on our R&D investment by coordinating activities within and with other Federal agencies such as the Department of Commerce, National Institutes of Standards and Technology and the Department of Interior.

6. Interagency Efforts to Implement Section 16 of the PSIA

Since our last testimony, we have designed and are testing a web-based environmental permit review process to: (a) provide early electronic notification of proposed pipeline repairs to Federal agencies, and solicit State and local agencies involved in the review process for pipeline repairs and (b) expedite coordination and approval of recommended best practices for operators to use to manage environmental damage when repairing their pipelines in environmentally important areas. This process meets the requirements of the PSIA by ensuring all environmental laws are addressed in the most efficient manner. A remaining issue is timely, consistent participation by all permitting agencies.

IV. We are Achieving Results

When we compare the years 2001-2005 to the previous five-year period of 1996-2000, the rate of hazardous liquid pipeline accidents has declined by 18 percent. In addition, by 2005 the volume of significant oil spills decreased by 34 percent from the previous 10 year average, and the 10-year average volume of net spills for the same period decreased 36 percent.

Pipeline excavation related accidents decreased over the past ten years by 59 percent. This outcome is largely due to the result of working with our State partners and the more than 900 volunteer members of the Common Ground Alliance who strive to foster damage prevention activities.

In the face of ten years of increased new construction, other accident types remain relatively stable. Accidents of most severe consequence, involving deaths and injuries are trending steadily downward.

In closing, I want to reassure the members of this Subcommittee, that the Administration, Secretary Mineta, and the hardworking men and women of PHMSA share your strong commitment to improving safety, reliability, and public confidence in our Nation's pipeline infrastructure.

I would be pleased to answer your questions.

MR. HALL. And I thank you very much.

Mr. Theodore Alves, Principal Assistant Inspector General for Audit and Evaluation, Office of Inspector General, we will recognize you, sir.

MR. ALVES. Thank you.

Mr. Chairman, Ranking Member, and members of the subcommittee, I appreciate the opportunity to testify today about progress that has been made in strengthening pipeline safety.

We have seen considerable progress since we first testified on this issue over 6 years ago. That progress is the direct result of the attention from this subcommittee, Secretary Mineta, and the Office of Pipeline Safety, as well as the States, industry, and other groups, such as the Common Ground Alliance.

The Office of Pipeline Safety has completed action on 18 of the 23 mandates from the 2002 Act. One outstanding mandate from 1992 establishing safety regulations for hazardous liquid gathering lines and low-stress transmission lines is scheduled to be completed by the end of this year.

This focus on implementing congressional mandates has significantly improved pipeline safety, but we are not yet at an end state because operators are in the early stages of implementing integrity management programs.

Today, I would like to make six points.

First, operators are identifying integrity threats and making timely repairs. Although operators have not yet fully implemented their integrity management programs, they are making good progress completing baseline assessments, and they are on track to complete the assessments. Preliminary indications are that the program is identifying and the operators are repairing a significant number of integrity threats. Our auditors visited seven hazardous liquid pipeline operators and found that they had repaired all 409 integrity threats we had examined. About 98 percent of the repairs were also completed within established timeframes.

Second, reports from six of the seven hazardous liquid operators we visited contained errors. The errors were due to several factors, such as using preliminary data or data outside the reporting period. Accurate reports are important to the Office of Pipeline Safety's risk-based oversight approach, and the Office is working with operators to improve their reporting.

Third, the Office of Pipeline Safety inspection program is helping operators improve safety. As of December of 2005, the Office of Pipeline Safety and its State partners had conducted inspections at over 86 percent of the 249 hazardous liquid operators. At one operator we visited, inspectors found threats that had not been repaired in a timely manner. The operator has since made the repairs.

Fourth, the Office of Pipeline Safety and a broad range of stakeholders now agree that natural gas distribution operators should implement integrity management programs. This is important because nearly all distribution pipelines are in high-consequence areas where a rupture could have severe consequences. And while actual numbers remain low, injuries and fatalities involving distribution pipelines have gone up over the last 5 years. The Pipeline Safety Office is drafting a rule calling for operators to develop integrity management plans during 2008, and to begin implementing those plans in 2009.

Fifth, security responsibilities still need to be clarified. DOT and DHS have signed a Memorandum of Understanding to improve their security coordination. Even though Congress told DOT and DHS in October of 2004 to come up with an annex to their MOU clarifying roles and responsibilities for pipeline security, this has not been done. The lack of clearly defined roles could lead to duplicative or conflicting efforts and the potential for an uncoordinated response to a terrorist attack.

Finally, Congress may wish to consider strengthening the Secretary's authority to waive safety regulations during a disaster. By law, the Secretary may waive the pipeline safety regulation, but only after public notice and an opportunity for a hearing. With an emergency like Katrina, this requirement may not always be practical. In fact, during Katrina, loss of electrical power to pumping stations forced three major operators to shut down, cutting off most sources of fuel to the eastern seaboard. The Pipeline Safety Office sent inspectors to oversee manual operations and remote pumping stations. That direct oversight avoided any question about whether a waiver was required to operate the system safely, but in a future emergency, a waiver might be the only way to respond in a timely manner.

Mr. Chairman, this concludes my statement. I will be pleased to answer any questions that you or other members may have.

[The prepared statement of Theodore Alves follows:]

PREPARED STATEMENT OF THEODORE ALVES, PRINCIPAL ASSISTANT INSPECTOR GENERAL FOR AUDIT AND EVALUATION, OFFICE OF INSPECTOR GENERAL, U.S. DEPARTMENT OF TRANSPORTATION

Summary

The Office of Pipeline Safety (OPS) is making good progress in implementing congressional mandates and improving pipeline safety. I would like to briefly summarize my major points.

Operators are identifying integrity threats and making timely repairs. Although operators have not yet fully implemented their Integrity Management Programs (IMP), preliminary indications show that the baseline integrity assessments of hazardous liquid and natural gas transmission pipelines are working well. In our current review of integrity threats to hazardous liquid pipelines, we found that operators had repaired all 409 threats we examined, with approximately 98 percent of the repairs having been completed on time.

However, pipeline operator reports contain errors and OPS needs to work with operators to improve their reporting. Six of the seven hazardous liquid pipeline operators we visited had errors in their annual reports. OPS is taking steps to improve the accuracy of operator annual reports but needs to verify the accuracy of reported threat data during integrity management inspections. Inaccurate reports degrade OPS's ability to analyze integrity threats, identify important trends, and focus limited inspection resources.

OPS's integrity management inspection program is helping operators comply with the IMP requirements. As of December 2005, OPS and its state partners had conducted one or more integrity management inspections for over 86 percent of the 249 hazardous liquid pipeline operators. We also have seen evidence that OPS's enforcement program is helping to improve pipeline safety.

Initiatives are underway to establish IMPs for natural gas distribution pipelines. OPS, its state partners, and a broad range of stakeholders agree that all gas distribution pipeline operators should implement IMPs. OPS is drafting a rule requiring IMPs for all gas distribution operators and plans to have the final rule issued in mid-2007. It expects operators of natural gas distribution pipeline systems to develop integrity management plans during 2008 and begin implementing those plans in 2009.

OPS and TSA need to establish their respective pipeline security roles and responsibilities. In September 2004, the Departments of Transportation and Homeland Security signed a Memorandum of Understanding (MOU) to improve their cooperation and coordination. Now OPS and the Transportation Security Administration (TSA) need to spell out their roles and responsibilities at the operational level in an annex to the MOU. A lack of clearly defined roles among OPS and TSA at the working level could lead to duplicating or conflicting efforts, less than effective intergovernmental relationships, and—most importantly—the potential for an uncoordinated response to a terrorist attack.

The Secretary's waiver authority for responding to disasters may need to be strengthened. OPS took an active role in responding to and recovering from Hurricane Katrina disruptions to the pipeline system. By law, the Secretary of Transportation is authorized to grant waivers of pipeline safety requirements only after public notice and an opportunity for a hearing. It may not always be possible for OPS and pipeline operators to work around waiver requirements. Thus, Congress should consider whether the Secretary's waiver authority for responding to a disaster involving pipeline transportation needs to be strengthened.

Mr. Chairman, Ranking Member, and Members of the Subcommittee:

We appreciate the opportunity to testify today on the progress and remaining challenges in strengthening pipeline safety. We have done a great deal of work over the years evaluating the Department of Transportation's (DOT) efforts to improve pipeline safety and have issued a number of reports and testified several times before this Subcommittee and other congressional subcommittees about progress and challenges the Department and industry have faced.

The pipeline infrastructure consists of an elaborate network of more than 2 million miles of pipeline moving millions of gallons of hazardous liquids and more than 55 billion cubic feet of natural gas daily. The pipeline system is composed of predominantly three segments—hazardous liquid transmission pipelines, natural gas transmission pipelines, and natural gas distribution pipelines—and has about 2,200[1] natural gas pipeline operators and 250 hazardous liquid pipeline operators.

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[1] Of the 2,200 operators of natural gas pipelines, there are approximately 1,300 operators of natural gas distribution pipelines and 880 operators of natural gas transmission pipelines.

Within the DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA), the Office of Pipeline Safety (OPS) is responsible for overseeing the safety of the Nation's pipeline system. This oversight is important because pipelines, while fundamentally a safe way to transport these inherently dangerous resources, are subject to forces of nature, human actions, and material defects that can cause potentially catastrophic events. OPS sets safety standards that pipeline operators must meet when designing, constructing, inspecting, testing, operating, and maintaining their pipelines. In general, OPS is responsible for enforcing regulations over interstate pipelines and certifies programs the states implement to ensure the safety of intrastate pipelines.

Today, I would like to discuss three major points regarding pipeline safety:

- Progress made in implementing integrity management program (IMP) requirements and the challenges that remain.
- Initiatives underway to strengthen the safety of natural gas distribution pipeline systems.
- Need for clearer lines of authority to address pipeline security and disaster response.

Before I discuss these points, I would like to briefly summarize the considerable progress we have seen since we first testified on pipeline safety over 6 years ago. This progress is the direct result of congressional attention, including that of this Subcommittee; high-level management attention under the leadership of Secretary Mineta; and OPS's priority to improve its pipeline safety program. This progress started under what was then the Research and Special Programs Administration and continues today under PHMSA, which was created under the Norman Y. Mineta Research and Special Programs Improvement Act. Even during this reorganization, OPS was able to sustain its progress in improving pipeline safety.

As an indication that we were seeing clear signs of improvement, we removed pipeline safety from our DOT top management challenge report in 2002. As we testified before the House Subcommittee on Highways, Transit, and Pipelines on the reauthorization of the pipeline safety program in February 2002, OPS was making progress in implementing prior congressional mandates and our recommendations. However, with 8 mandates open from 1992 and 1996, plus an additional 23 mandates enacted in the Pipeline Safety Improvement Act of 2002, a lot of work remained.

Our June 2004 report,[2] "Actions Taken and Needed To Improve Pipeline Safety," recognized OPS's continued progress in clearing out most, but not all, of the congressional mandates enacted in 1992 and 1996. This included completing the development of the national pipeline mapping system and issuing regulations requiring IMPs for operators of hazardous liquid and natural gas transmission pipelines. These results were included in our last testimony before this Subcommittee in July 2004.

In our October 2005 report,[3] we again recognized that OPS's progress in closing out the long-overdue mandates and National Transportation Safety Board safety recommendations. Currently, there is only one open mandate from 1992, and OPS expects to close it by the end of 2006 through a rulemaking establishing safety regulations for hazardous liquid gathering lines and low stress transmission pipelines. The importance of completing and finalizing this rule cannot be overstated as it is pertinent to the low stress transmission pipeline that failed just last month on the North Slope of Alaska. As a result of the failure, an estimated 200,000 gallons of crude oil spilled, impacting the Arctic tundra and covering approximately 2 acres of permafrost.

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[2] OIG Report No. SC-2004-064, "Actions Taken and Needed for Improving Pipeline Safety," June 14, 2004.

[3] OIG Report No. SC-2006-003, "Actions Taken and Needed in Implementing Mandates and Recommendations Regarding Pipeline and Hazardous Materials," October 20, 2005. See OIG reports on this website: www.oig.dot.gov.

All of the mandates from 1996 are closed, and OPS has completed actions on 18 of the 23 mandates from the 2002 Act. Three of these open mandates are not yet late, since the congressional deadlines for completing them have not come due.

Clearly, OPS is making good progress in implementing congressional mandates and improving pipeline safety, but it is not at an end state because operators are in the early stages of implementing IMPs. I would now like to turn to my three points on pipeline safety.

Progress Made in Implementing Integrity Management Program Requirements and the Challenges That Remain. The most important congressional mandates required IMPs for operators of hazardous liquid and natural gas transmission pipelines. Operators are required to identify their pipelines in or potentially affecting high-consequence areas (HCA)[4] and assess their pipelines for risk of a leak or failure using smart pigs[5] or equivalent inspection methods. Hazardous liquid pipeline operators were first to come under the new IMP requirements, starting in 2001. Natural gas transmission pipeline operators followed 3 years later. Operators were also required to categorize and repair integrity threats within specified timeframes and to report these threats to OPS.

Although operators have not yet fully implemented their IMPs, preliminary indications show that the baseline integrity assessments of hazardous liquid and natural gas transmission pipelines are working well, and there was *clearly a need for such assessments* because the assessments led operators to identify and correct a significant number of integrity threats. This is a key outcome as the IMP is the backbone of OPS's risk-based approach to overseeing pipeline safety.

According to data provided by OPS, hazardous liquid and natural gas transmission pipeline operators have identified all of their HCAs and are well on their way toward completing their baseline assessments on time. As of December 31, 2004 (the latest data reported), hazardous liquid operators had completed baseline assessments of approximately 95 percent of their pipeline systems in or potentially affecting HCAs, even though they have until 2009 to do so. In comparison, at the end of 2005, natural gas transmission pipeline operators had completed around 33 percent of their baseline assessments of pipelines in or potentially affecting HCA pipeline systems, but they have until 2012 to complete the assessments.

Operator baseline assessments have been instrumental in helping identify and repair a significant number of integrity threats. In our current review of integrity threats to hazardous liquid pipelines, we found that operators had repaired all 409 threats we examined, with approximately 98 percent of the repairs completed within established IMP timeframes or OPS-approved extensions. OPS has also made noticeable progress in overseeing IMP implementation through its integrity management inspection program, and we have seen examples of OPS directing operators to take corrective actions when violations were found. As of December 2005, OPS and its state partners had conducted one or more integrity management inspections of 86 percent (215 of 249) of hazardous liquid pipeline operators.

However, we have concerns with the reports submitted to OPS on integrity threats. Specifically, six of the seven hazardous liquid pipeline operators we visited had errors in their reports. Reporting errors were due to a variety of factors, such as the submission of preliminary numbers, of data outside the reporting period, or of threats involving non-HCA pipeline segments. OPS is taking steps to improve the accuracy of operator annual reports and to help operators better understand the reporting requirement. But OPS needs to review integrity threat data and related documentation as part of its integrity management inspection program. Our primary concern is that OPS's risk-based approach to safety relies on accurate reporting from operators. Inaccurate reports degrade OPS's ability to analyze integrity threats, identify important trends, and focus limited inspection resources on areas of greatest concern.

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[4] HCAs include unusually sensitive areas (defined as drinking water or ecological resource areas), urbanized and other populated places, and commercially navigable waterways.

[5] A "smart pig" is an in-line inspection device that traverses a pipeline to detect potentially dangerous defects, such as corrosion.

Initiatives Underway To Strengthen the Safety of Natural Gas Distribution Pipeline Systems. In our June 2004 report, we recommended that OPS require operators of natural gas distribution pipelines to implement some form of pipeline integrity management or enhanced safety program with the same or similar integrity management elements as the hazardous liquid and natural gas transmission pipelines.

Since 2004, there has been a sea change in the industry toward integrity management for natural gas distribution pipeline systems. OPS, in partnership with the industry stakeholders, is developing a plan to strengthen the safety of natural gas distribution pipeline systems using integrity management principles. So far, the process for developing a natural gas distribution IMP has worked well, and indications are that progress will continue.

Although much has been accomplished, much more remains to be done before distribution IMPs can be implemented. OPS, its state partners, and a broad range of stakeholders have decided that all distribution pipeline operators, regardless of size, should implement an IMP. OPS is drafting a rule requiring integrity management for all gas distribution operators and plans to have the final rule issued in mid-2007. It expects operators of natural gas distribution pipeline systems to develop integrity management plans during 2008 and begin implementing those plans in 2009.

Need for Clearer Lines of Authority To Address Pipeline Security and Disaster Response. Not only is it important that we ensure the safety of the Nation's pipeline system, but we must also ensure the security and recovery of the system in the event of a terrorist attack or natural disaster.

Since we last testified before this Subcommittee on the issue of pipeline security in July 2004, DOT and the Department of Homeland Security (DHS) signed a Memorandum of Understanding (MOU) to improve their cooperation and coordination in promoting the safe, secure, and efficient movement of people and goods throughout the U.S. transportation system. Finalizing the MOU was the first critical step in what is a very dynamic process. However, OPS and the Transportation Security Administration (TSA) still need to spell out their roles and responsibilities at the operational level in an annex to the MOU. A lack of clearly defined roles among OPS and TSA at the working level could lead to duplicating or conflicting efforts, less than effective intergovernmental relationships, and—most importantly—the potential for an uncoordinated response to a terrorist attack.

With respect to natural disasters, OPS took an active role in responding to and recovering from Hurricane Katrina disruptions in the pipeline system. What we learned from this disaster is that, by law, the Secretary of Transportation is authorized to grant waivers of pipeline safety requirements only after public notice and an opportunity for a hearing. However, with an emergency like Katrina, this would not have been practical. Katrina disruptions to the pipeline system caused the pipeline operators to switch their operations from automated to manual. When responding to Katrina, OPS had to send its inspectors out to remote pumping stations immediately following the storm to personally ensure that the pipeline operator personnel were technically qualified to operate the pipeline systems manually and keep the fuel flowing.

It may not always be possible for OPS and pipeline operators to work around waiver requirements, as occurred in this case. Therefore, Congress should consider whether the Secretary's waiver authority for responding to a terrorist attack or disaster involving pipeline transportation needs to be strengthened.

Specific Observations

I. Progress Made in Implementing Integrity Management Program Requirements and the Challenges That Remain

Operators Are Making Significant Progress in Fulfilling IMP Requirements. According to data provided by OPS, hazardous liquid and natural gas transmission pipeline operators have made significant progress in recent years in implementing key elements of their IMPs. For example, according to OPS, both pipeline segments have identified all of their HCAs. Operators are also well on their way toward completing their baseline assessments of pipeline systems in or affecting HCAs. As Table 1 indicates, operators have completed baseline assessments on approximately 77 percent of their pipeline systems as of December 31, 2004, with hazardous liquid and natural gas transmission segments completing approximately 95 percent and 18 percent, respectively. This latter figure jumps to 33 percent when 2005 assessment numbers are added.[6]

Table 1. Completed Baseline Assessments
(As of December 31, 2004)

Operator	**HCAs***	**Baseline Assessments***	**% Completed**
Hazardous Liquid	71,903	67,982	95%
Natural Gas Transmission	21,727	3,947	18%
Total	**93,630**	**71,929**	**77%**

* Measured in pipeline miles

Although hazardous liquid and natural gas transmission pipeline operators are only required to assess pipelines in or potentially affecting HCAs, some operators—on their own initiative—have extended their baseline assessments to some of their non-HCA pipeline segments. For example, hazardous liquid pipeline operators have conducted baseline assessments on over a quarter of their non-HCA pipelines as of December 31, 2004.

Large Numbers of Integrity Threats Are Being Identified and Repaired on Time, Although Operator Annual Reports Need Improvement. According to OPS, tens of thousands of hazardous liquid pipeline integrity threats have been discovered and repaired as of the end of 2004. Approximately one quarter of these threats fell into time-sensitive repair categories of immediate, 60-day, or 180-day. The majority of threats were categorized as "other," which are not considered time-sensitive. In our current review of integrity threats to hazardous liquid pipelines, we found that operators had repaired all 409 threats[7] we examined, with approximately 98 percent of the repairs completed within established IMP timeframes or OPS-approved extensions.

While recognizing IMP success in identifying and repairing integrity threats, we have concerns with the reports submitted to OPS on integrity threats. OPS uses the data in these reports, much of which is available to the public, in a variety of ways, including identifying important trends, prioritizing integrity management inspections, and monitoring industry performance and regulatory compliance. Yet, our current review found reporting errors in the integrity threat data submitted by six of the seven operators we visited. We asked each of the seven operators to re-examine the 2004 threat data that they reported to OPS. Six of the seven operators acknowledged having made errors in their annual reports, in some cases significant errors. For example, one operator's numbers of immediate, 60-day, and 180-day threats reported to OPS had to be increased by 49 percent (i.e., from 53 to 79). In a second example, the operator had to decrease his numbers by 41 percent (i.e., from 186 to 110).

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[6] We do not have 2005 data for hazardous liquid pipeline operators since their annual reports are not due to OPS until June 15, 2006. In comparison, natural gas pipeline operators were required to submit their 2005 data by February 28, 2006.

[7] Our sample of 409 threats was pulled from operator data bases, not from information reported to OPS.

These reporting errors were due to a variety of factors. For example, one operator mistakenly reported preliminary pig data instead of actual numbers obtained from subsequent excavation and repair work. A second operator reported integrity threat data involving non-HCA pipeline segments. Other types of errors included reporting data outside the 2004 reporting period and entering numbers relating to pipeline mileage rather than integrity threats. Our primary concern is that OPS's risk-based approach to safety needs accurate reporting from operators. Inaccurate reports hamper OPS's ability to analyze threat data, identify important trends, and focus limited inspection resources on areas of greatest concern.

OPS officials are taking steps to improve the accuracy of operator reports and to help operators better understand new reporting requirements. OPS plans on issuing new reporting guidelines by mid-2006, including clearer definitions of each threat category. Starting in January 2006, OPS began posting operator annual integrity threat reports to its public website as a means of providing transparency and encouraging greater accuracy. While these efforts to improve the accuracy of operator IMP reports should help, OPS needs to have operators verify the accuracy of threat data contained in their earlier annual reports and submit revised data if errors are found. OPS also needs to verify the accuracy of the integrity threat data as part of its integrity management inspection program.

OPS Inspection and Enforcement Programs Are Helping Achieve Operator Compliance With IMP Requirements. OPS has made progress in overseeing IMP implementation through its inspection and enforcement programs. During inspections for both hazardous liquid and natural gas transmission pipeline operators, OPS and state inspectors look at whether operators: (1) perform a thorough and effective review of pig results, (2) identify all integrity threats in a timely manner, (3) remediate integrity threats in a timely manner, and (4) use the appropriate repair or remediation methods. As of December 2005, OPS and its state partners had conducted one or more integrity management inspections of 86 percent (215 of 249) of hazardous liquid pipeline operators. Even more important, those operators inspected were responsible for approximately 98 percent of all pipeline miles in or potentially affecting HCAs. With respect to natural gas transmission pipeline operators, which OPS only recently began inspecting, OPS had completed inspections on 10 percent (11 of 110) of the operators for which it is responsible as of March 2006.

During our current review of integrity threats, we found evidence of how the OPS enforcement program is helping to improve pipeline safety. At one of the seven operators we reviewed, OPS inspectors found that the operator had failed to discover integrity threats (approximately 160) due to an error in analyzing pig data. Although the operator had identified the error and had asked the pig vendor to recalculate the data, subsequent repairs were not completed before an integrity management inspection 2 months later. OPS directed the operator to make necessary corrections and warned the operator that OPS would take enforcement action should the operator not address the problem. The operator has since made the necessary repairs.

OPS also took action against Kinder Morgan Energy Partners. On August 24, 2005, OPS issued a Corrective Action Order to Kinder Morgan in response to numerous accidents in its Pacific Operations unit and designated the entire unit as a "hazardous facility."[8] The Corrective Action Order requires a thorough analysis of recent incidents, a third-party independent review of operations and procedural practices, and a restructuring of Kinder Morgan's internal inspection program. On April 10, 2006, OPS and Kinder Morgan entered into a consent agreement that met all of the elements of the Order.

II. Initiatives Underway To Strengthen the Safety of Natural Gas Distribution Pipeline Systems

OPS has implemented IMP requirements for hazardous liquid and natural gas transmission pipelines. No similar requirements presently exist for natural gas distribution pipelines, and we have recommended that some form of pipeline integrity management or enhanced safety program be required. Since 2004, there has been a sea change in the industry toward integrity management for natural gas distribution pipeline systems.

The natural gas distribution system makes up over 85 percent (1.8 million miles) of the 2.1 million miles of natural gas pipelines in the United States. Nearly all of the natural gas distribution pipelines are located in highly populated areas, such as business districts and residential communities, where a rupture could have the most significant consequences.

When we testified in July 2004, our concern then was, as it is today, that the Department's strategic safety goal of reducing the number of transportation-related fatalities and injuries was not being achieved by natural gas distribution pipelines. In the 10-year period from 1996 through 2005, OPS's data show accidents in natural gas distribution pipelines have caused more than *3.5 times* the number of fatalities (173 fatalities) and nearly *4.0 times* the number of injuries (616 injuries) as the combined total of 48 fatalities and 156 injuries for hazardous liquid and gas transmission pipeline accidents. In the past 5 years, the number of fatalities and injuries from accidents involving natural gas distribution pipelines has increased from 5 fatalities and 46 injuries in 2001 to 17 fatalities and 48 injuries in 2005. Given that most pipeline fatalities and injuries involve natural gas distribution pipelines, OPS needs to ensure that it moves quickly to enhance the safety of these pipelines.

Initiatives Leading up to the Development of a Natural Gas Distribution Integrity Management Program. To close the safety gap on natural gas distribution pipelines, we recommended in our June 2004 report on pipeline safety that OPS require operators of natural gas distribution pipelines to implement some form of pipeline integrity management or enhanced safety program with the same or similar integrity management elements as those for hazardous liquid and natural gas transmission pipelines.

In its fiscal year 2005 report, the Conference Committee on Appropriations recognized the need for enhancements in the safety of natural gas distribution pipelines and agreed with the findings of our June 2004 report that certain IMP elements can readily be applied to this segment of the industry, such as developing timeframes on how often inspections should take place and when repairs should be made. The Committee directed OPS to submit a report detailing the extent to which integrity management plan elements may be applied to natural gas distribution pipeline systems to enhance safety. The report was submitted in May 2005 with detailed specific milestones and activities, including the development of requirements, guidance, and standards.

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[8] Normally OPS will designate pipeline segments immediately adjacent to a rupture a "hazardous facility." This Corrective Action Order designated the entire Pacific Operations unit a "hazardous facility" because of OPS's conclusion that the unit had systemic problems with its IMP.

As part of the initiatives in collecting data to prepare the report for the Committee, in December 2004, OPS held a public meeting on enhancing integrity management of natural gas distribution pipelines. OPS invited our office to participate in the meeting and present our views. At the meeting, we outlined three areas that in our view were fundamental to integrity management: understanding the infrastructure, identifying and characterizing the threats, and determining how best to manage the known risks (i.e., prevention, detection, and mitigation). These three areas are essentially the same as those underlying the natural gas transmission IMP and would become the foundation for building a natural gas distribution IMP.

Identifying the Need for and Developing a Distribution IMP. In its report to Congress in May 2005, OPS outlined the extent to which integrity management plan elements could be applied to natural gas distribution pipeline systems to enhance safety. A December 2005 report prepared by OPS, its state partners, and a broad range of stakeholders concluded that all distribution pipeline operators, regardless of size, should implement an IMP that includes seven key elements, three of which are fundamental to integrity management: know the infrastructure, identify the threats, and assess and prioritize risks. OPS is currently drafting a rule to implement IMP requirements for operators of natural gas distribution pipelines.

With respect to identifying and characterizing threats, the December 2005 report points out that "excavation damage poses by far the single greatest threat to distribution systems safety, reliability, and integrity: therefore excavation damage prevention presents the most significant opportunity for distribution pipeline safety improvements."

The source of excavation damage to distribution pipelines can be from anyone who has a reason to dig underground, such as homeowners, landscapers, local water and sewer departments or their contractors, cable companies, electric companies, and owners and operators of distribution pipeline systems or their contractors.

The December 2005 report also points out that what is needed to prevent excavation damage to distribution pipelines in the first place is a comprehensive damage prevention program that includes nine important elements, such as enhanced communication between operators and excavators, partnership in employee training, partnership in public education, and fair and consistent enforcement of the law.

An important factor in preventing excavation damage is a well-established one-call system that excavators must use by law before they dig in an area of a pipeline. A one-call notification system is already in place and provides a telephonic link between excavators and operators of underground pipeline and facilities. The heart of the system is an operational center whose main function is to transfer information from excavators about their intended excavation activities to the operators of underground pipelines and facilities participating in the system.

To further enhance this service, the Federal Communication Commission established a three-digit number—811—for one-call systems that excavators and the public can use to easily connect to the appropriate one-call center. It is anticipated that the 811 number will increase the use of the one-call system service and help avoid excavation damage. Under the Federal Communication Commission rule, the 811 number must be used as the dialing code for one-call centers by April 13, 2007. Currently, implementation lies at the state level, with at least one center already accepting calls directed to 811.

We believe a comprehensive damage prevention program is needed as outlined in the December 2005 report[9] and that Congress may want to consider legislation to support the development and implementation of the damage prevention program with special emphasis on effective enforcement.

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[9] The December 2005 report, "Integrity Management for Gas Distribution," was prepared by OPS, its state partners, and a broad range of stakeholders.

III. Need for Clearer Lines of Authority To Address Pipeline Security and Disaster Response

The attacks of September 11, 2001, and the devastation and destruction of Hurricane Katrina, which hit on August 29, 2005, demonstrated the vulnerabilities of the Nation's critical transportation and energy infrastructure to catastrophic events. What has become clear as a result of these events is the continuing need for a well-defined, well-coordinated interagency approach for preparing for, responding to, and recovering from such events.

DOT has the responsibility of working with other agencies to secure the U.S. transportation system and protect its users from criminal and terrorist acts. In our report "DOT's Top Management Challenges" for FY 2005 and 2006, we discussed the growing interdependency among Federal agencies in this area. The imperative for DOT is to effectively integrate new security measures into its existing safety regimen and to do so in a way that promotes stronger security without degrading transportation safety and efficiency.

Initiatives Clarifying Security Responsibilities. Certain steps have been taken to establish what agency or agencies would be responsible for ensuring the security of the Nation's critical infrastructure, including pipelines. For example, in December 2003, Homeland Security Presidential Directive 7:

- Assigned DHS the responsibility for coordinating the overall national effort to enhance the protection of the Nation's critical infrastructure and key resources.
- Assigned the Department of Energy the responsibility for ensuring the security of the Nation's energy, including the production, refining, storage, and distribution of oil and gas.
- Directed DOT and DHS to collaborate on all matters relating to transportation security and transportation infrastructure protection and to the regulation of the transportation of hazardous materials by all modes, *including pipelines*.

Although the Presidential Directive directs DOT and DHS to collaborate in regulating the transportation of hazardous materials by all modes, including pipelines, it is not clear from an operational perspective what OPS's relationship will be with TSA.

Identifying the Need for Clarifying Security Roles and Responsibilities. In our July 2004 testimony, we reported that it was unclear which agency or agencies will have responsibility for pipeline security rulemaking, oversight, and enforcement and recommended that the delineation of roles and responsibilities between DOT and DHS be spelled out by executing an MOU or Memorandum of Agreement.

Since then, DOT and DHS signed a MOU in September 2004 to improve their cooperation and coordination in promoting the safe, secure, and efficient movement of people and goods throughout the U.S. transportation system. Finalizing the MOU was the first critical step, but much more remains to be sorted out between the two departments. For example, the delineation of roles and responsibilities between OPS and TSA needs to be spelled out by executing a security annex to the MOU specifically relating to pipelines.

In the October 2004 House Report[10] accompanying the Norman Y. Mineta Research and Special Programs Improvement Act (Public Law 108-426), which created PHMSA, the Committee strongly urged DOT and DHS to execute an agreement clarifying the roles, responsibilities, and resources of the departments in addressing pipeline and hazardous materials transportation security matters upon establishment of the new agency. Today, this has still not been done.

Resolving pipeline security roles and responsibilities between OPS and TSA is necessary to avoid, at the working level, duplicating or conflicting efforts, less than effective intergovernmental relationships, and—most importantly—the potential for problems in responding to terrorism. OPS already has a set of well-established security requirements pre-dating September 11th that it oversees and enforces for operators of liquid petroleum gas facilities. What is not clear in this situation is whether oversight and enforcement remains with OPS or whether it will be transferred to TSA.

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[10] House Report No. 108-749, dated October 6, 2004.

The pipeline industry clearly supports the need for a security regimen but has pointed out to us that it does not need two separate agencies overseeing two separate sets of rules and that the issue of security roles and responsibilities needs to be clarified and formalized.

We agree that the roles and responsibilities of OPS and TSA for pipeline security-related subjects need to be clarified. These subjects include security grant activities, emergency communication, rulemaking and adjudications, and the oversight and enforcement jurisdiction of TSA and OPS inspectors.

Identifying the Need for Waiver Authority When Responding to Disasters. In addition to security issues, the growing interdependency among Federal agencies can be found in their response to catastrophic natural or man-made disasters. The National Response Plan, adopted in December 2004, requires extensive coordination, collaboration, and information sharing between Federal, state, local, and tribal governments to prevent, prepare for, respond to, and recover from any type of national incident, such as Hurricane Katrina.

We would like to recognize OPS's efforts in preparing for, responding to, and recovering from Hurricane Katrina disruptions on the pipeline system. Loss of electrical power to their pumping stations forced three major pipeline operators to shut down. This eliminated most sources of fuel to the entire Eastern seaboard and led to a wide array of economic disruptions, including hoarding and severe price spikes. OPS's efforts immediately following Hurricane Katrina included, among other things, deploying teams to move generators to pipeline pumping stations so that the flow of petroleum products to the Southeastern and Mid-Atlantic regions was restored.

When OPS was preparing for Katrina, a question was raised about whether the Secretary had the authority to waive compliance with pipeline safety regulations. By law, the Secretary may waive regulations but only after public notice and an opportunity for a hearing. However, with an emergency like Katrina, this would not have been practical. Katrina disruptions to the pipeline system caused the pipeline operators to switch their operations from automated to manual. When responding to Katrina, OPS had to send its inspectors out to remote pumping stations immediately following the storm to personally ensure that the pipeline operator personnel were technically qualified to operate the pipeline systems manually and keep the fuel flowing. It may not always be possible for OPS and pipeline operators to work around waiver requirements, as occurred in this case.

The economic disruptions from Katrina were felt immediately and notifying the public and holding a hearing would have significantly delayed restoring the flow of energy, causing severe economic consequences. Given the lessons learned from Hurricane Katrina, Congress should consider whether the Secretary's waiver authority for responding to a terrorist attack or disaster involving pipeline transportation needs to be strengthened.

Mr. Chairman, this concludes my statement. I will be pleased to answer any questions that you or the other members might have.

MR. HALL. And thank you very much, sir.

Mr. Robert Chipkevich, Director, Office of Railroad, Pipeline and Hazardous Materials Investigations, the National Transportation Safety Board, we recognize you, sir.

MR. CHIPKEVICH. Thank you, sir.

Good morning, Chairman Hall, Ranking Member Boucher, and members of the subcommittee.

Since I last testified before this committee in March of 2002, the Pipeline and Hazardous Materials Safety Administration has continued to make progress to improve pipeline safety. I would like to briefly highlight a few of the safety issues.

After a series of pipeline accidents, the Safety Board had recommended that PHMSA assess industry public education programs and to require pipeline operators to periodically evaluate the effectiveness of those programs. In December of 2003, the American Petroleum Institute published Recommended Practice 1162 and addressed these issues in that. And then in May of 2005, PHMSA incorporated the recommended practices into its safety requirements.

Progress has also been made in the area of mandatory pipeline integrity assessments. The Safety Board had recommended periodic inspections of pipelines to identify corrosion, mechanical damage, and other time-dependent defects that could be detrimental to the safe operation of pipelines. Other rules were published that required both liquid and gas transmission line operators to conduct these integrity assessment programs. The safety board supported that rulemaking and then closed the recommendation that was made in 1987.

PHMSA must now ensure that the pipeline operators implement effective integrity management programs. Quantifying inputs into various risk managed models can be difficult and subjective. And PHMSA has shared its inspection protocols with the Safety Board, and as we investigate accidents that could involve integrity issues, we will examine its process for evaluating those integrity management programs.

In 2001, after investigating an accident that had involved the explosion of a new home in South Riding, Virginia, the Safety Board again recommended that PHMSA require gas pipeline operators to install excess flow valves in all new and renewed gas service lines when operating conditions are compatible with readily available valves, only about one-half of the operators currently install these valves at their cost. Excess flow valves should be a stand-alone requirement and not the result of a decision based on risk analysis. Risk factors may change over time due to community growth or other events, and the cost of excavating existing service to homes to install excess flow valves would be another factor to then overcome. The excess flow valves are inexpensive, and they are safety devices that we believe can save lives.

PHMSA's final rule on operator qualification training and testing standards was issued in 2001 that focused on qualifying individuals for pertaining certain tasks. However, at that time, it did not require training or specify maximum intervals for re-qualifying personnel. Last year, PHMSA published a rule that now requires operators to provide training and held public hearings to explore ways to further strengthen the operator qualifications rules. These developments are positive and the Safety Board continues to urge PHMSA to move forward on this important issue. The Board does believe that operator qualification requirements must include training, testing to determine if the training was effective, and the re-qualification of personnel on a timely basis.

Finally, the Safety Board recently completed a study on a series of accidents that involved delayed reaction by pipeline controllers. The study found that an effective alarm audit review system by operators would increase the likelihood of controllers responding appropriately to alarms associated with pipeline leaks and recommended that PHMSA required such type reviews by operators.

The Safety Board will continue to review activities involving pipeline safety, and we do believe, overall, in the past 5 years, there has been progress in this area.

Mr. Chairman, that completes my statement. I would be happy to answer your questions when you are ready.

[The prepared statement of Robert Chipkevich follows:]

PREPARED STATEMENT OF ROBERT CHIPKEVICH, DIRECTOR, OFFICE OF RAILROAD, PIPELINE, AND HAZARDOUS MATERIALS INVESTIGATIONS, NATIONAL TRANSPORTATION SAFETY BOARD

Good morning Chairman Hall, Ranking Member Boucher, and Members of the Subcommittee. My name is Bob Chipkevich. I am the Director of the National Transportation Safety Board's Office of Railroad, Pipeline and Hazardous Materials Investigations. The Safety Board's Acting Chairman, Mark Rosenker, asked me to represent the Board today to discuss pipeline safety.

The Safety Board is currently investigating pipeline accidents in Dubois, Pennsylvania, involving a leaking butt fusion joint in a 2-inch diameter plastic gas main; Kingman, Kansas involving the failure of an 8-inch diameter hazardous liquid pipeline carrying anhydrous ammonia; and, Bergenfield, New Jersey where an apartment building was destroyed. Excavation activities were being conducted adjacent to a natural gas service line located near the apartment building.

Since I last testified before this Subcommittee in March 2002, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has continued to make progress to improve pipeline safety.

After a series of natural gas pipeline accidents in Kansas in 1988 and 1989 and a liquid butane pipeline failure near Lively, Texas, in 1996, the Safety Board recommended that PHMSA assess industry programs for public education on the dangers of pipeline leaks and require pipeline operators to periodically evaluate the effectiveness of those programs.

In December 2003, the American Petroleum Institute published its Recommended Practice 1162, *Public Awareness Programs for Pipeline Operators,* that addressed these issues. And in May of 2005, PHMSA incorporated this Recommended Practice into its pipeline safety requirements.

PHMSA also has made progress in the area of mandatory pipeline integrity assessments. The failure of pipelines with discoverable integrity problems has been a safety issue identified in pipeline accidents investigated by the Safety Board for many years, and related safety recommendations date back to 1987. The Board recommended that PHMSA require periodic inspections or tests of pipelines to identify corrosion, mechanical damage, and other time dependent defects that could be detrimental to the safe operation of pipelines.

PHMSA published final rules in 2000 and 2002 requiring liquid pipeline operators to conduct integrity assessments in high-consequence areas. And in 2003, PHMSA issued similar requirements for natural gas transmission pipelines in high-consequence areas. Operators must now assess the integrity of these pipelines using in-line inspection tools, pressure tests, direct assessment, or other technologies capable of equivalent performance. PHMSA's rulemaking met the intent of the Safety Board's recommendations and we closed the safety recommendations as "acceptable action. "

As the Safety Board has previously noted, PHMSA will have to ensure that pipeline operators implement effective integrity management programs. Risk management principles, if properly applied, can be powerful tools to identify the risks to pipeline integrity and should lead operators to take action to mitigate those risks. Quantifying inputs into various risk management models, however, can be difficult and subjective. To ensure that the new rules for risk-based integrity management programs are effectively employed throughout the pipeline industry, it is important that PHMSA establish an effective evaluation program. PHMSA has shared its inspection protocols with the Safety Board, and when we investigate pipeline accidents that involve integrity issues we will examine the effectiveness of PHMSA's process for evaluating pipeline operators' integrity management programs.

In 2001, after investigating an accident that involved the explosion of a new home in South Riding, Virginia, the Safety Board again recommended that PHMSA require gas pipeline operators to install excess flow valves in all new and renewed gas service lines when operating conditions are compatible with readily available valves. PHMSA currently requires gas distribution operators, for new or renewed services, to either install the valves at their cost or notify customers of their option to have them installed at the customer's cost. Only about one-half of the operators currently install these valves at their cost.

We understand that PHMSA plans to incorporate a decision-making process for the installation of excess flow valves into its upcoming gas distribution integrity management rules. This would require each operator to employ a risk-based approach to consider the mitigation value of installing excess flow valves. PHMSA has asked the Gas Piping Technology Committee to develop guidance to address risk factors that would be appropriate for this determination.

The Safety Board believes that its recommendation to install excess flow valves should be a stand-alone requirement and not be the result of a decision based solely on risk analysis. A decision to install excess flow valves needs to be made when gas lines are newly installed or renewed. Once a service is installed, it normally has a very long life-- several decades-- before it must be renewed. Risk factors may change over time due to community growth or other future events, and the cost of excavating existing service to install excess flow valves would be another factor to overcome. Excess flow valves are inexpensive safety devices that can save lives. They should be installed whenever operating conditions are compatible with readily available valves.

In 1987, after investigating accidents in Kentucky and Minnesota, the Safety Board recommended that PHMSA require operators to develop training and testing programs to qualify employees. And following a 1996 accident in San Juan, Puerto Rico, the Board recommended that PHMSA complete its rulemaking on operator qualification, training, and testing standards.

PHMSA's final rule, issued in 2001, focused on qualifying individuals for performing certain tasks. The Safety Board noted that the final rule did not include requirements for training, nor did it specify maximum intervals for re-qualifying personnel. The safety recommendation was closed as "unacceptable action."

On March 3, 2005, PHMSA published a direct final rule that amended the pipeline personnel qualification regulations to conform to the Pipeline Safety Improvement Act of 2002. Among other changes, this rule required operators to provide training. And on December 15, 2005, PHMSA held a public meeting to explore several issues and potential ways to strengthen the operator qualification rule. The Safety Board believes that operator qualification requirements must include training, testing to determine if the training was effective, and the re-qualification of personnel on a timely basis.

Over the years, the Safety Board has investigated numerous accidents involving excavation damage to pipeline systems, and excavation damage continues to be a leading cause of pipeline accidents. Therefore, the recent effort of PHMSA and the Common Ground Alliance to establish a national one-call number -- 811 -- is especially noteworthy. Soon, contractors and homeowners across the country will have an easy-to-remember, easy-to-use means for getting underground utilities marked and identified before excavation activities begin. We hope that all States will move quickly to ensure that this number is incorporated into all telephone exchange systems.

Last year, the Safety Board completed a study of a series of liquid pipeline accidents that involved delayed reaction by pipeline controllers and made several safety recommendations to PHMSA. The study found that most controllers indicated that alarms represent the most important safety feature of Supervisory Control and Data Acquisition (SCADA) systems. However, two controllers reported receiving up to 100 alarms an hour and one manager noted a reduction from 5,000 alarms a day in the control center to 1,000 by working with controllers to develop guidelines for more realistic alarm set points. The study found that an effective alarm review/audit system by operators would increase the likelihood of controllers responding appropriately to alarms associated with pipeline leaks. The Board recommended that PHMSA require pipeline companies to have a policy for the review/audit of alarms and that controller training include simulator or non-computerized simulations for controller recognition of leaks. The study also found that most control center employees worked 12-hour shifts, but the shifts could be extended and the cycle of shifts changed. The Board believes that requiring operators to report information about controllers' schedules on accident reports could help PHMSA determine the contribution of fatigue to pipeline accidents and recommended that PHMSA require operators to provide related data.

Other safety issues with open recommendations include the need for determining the susceptibility of some plastic pipe to premature brittle-like cracking problems; ensuring that pipelines submerged beneath navigable waterways are adequately protected from damage by vessels; and requiring that new pipelines be designed and constructed with features to mitigate internal corrosion. Actions on these safety recommendations are classified as "acceptable response" by the Board.

The Safety Board will continue to review activities involving pipeline safety, but clearly progress has been made in the past 5 years.

Mr. Chairman, that completes my statement, and I will be happy to respond to any questions you may have.

MR. HALL. I thank you. And we will have questions a little bit later.

The Chair recognizes Ms. Siggerud, Director, Physical Infrastructure Issues, U.S. Government Accountability Offices for 5 minutes, ma'am. Thank you.

MS. SIGGERUD. Thank you, Mr. Chairman, Ranking Member Boucher, and members of the subcommittee. I appreciate the opportunity to participate in this hearing today on the Pipeline Safety Improvement Act. My testimony today is based on the preliminary results of our work on the effects of safety stemming from, first, PHMSA's integrity management program for natural gas transmission pipelines, and second, the requirement that pipeline operators reassess these pipelines for corrosion at least every 7 years. We will be reporting in more detail on both of those issues this fall.

I would also like to touch on how PHMSA has acted to strengthen its enforcement programs since I testified before this subcommittee almost two years ago. My statement is based on our review of laws, regulations, and discussions with a broad range of stakeholders. This includes 41 operators representing about 60 percent of the miles of pipeline assessed to date. We also surveyed 47 States involved in the program.

Early indications are that the integrity management program has enhanced public safety by requiring that operators identify and address the greatest risks to their pipelines in highly populated areas known as HCAs. We found broad support for the program among both operators and stakeholders concerned with safety and the environment. Benefits of the program include better knowledge of their pipeline systems and improved communications within their companies.

Pipeline operators are making good progress in assessing their pipelines. Since 2004, operators have assessed about 6,700 miles of their 20,000 miles of pipelines in HCAs and completed 338 repairs that, by definition, needed to be made immediately. While it is not possible to know how many of these repairs would have been identified without integrity management, it is clear that assessing pipelines identifies problems that would otherwise go undetected.

PHMSA has performed 12 inspections of operators and found that they are doing well in conducting their assessments and making identified repairs. However, some are having difficulty in the documentation of their management processes. Operators we contacted also expressed some confusion about how they can tell whether their documentation will be sufficient.

PHMSA has also been working to improve communication with States about their role in overseeing the integrity management program. States do play a significant part in integrity management, and most State pipeline officials reported that they have started, or will start, inspections of intrastate operators this year. However, most also said they are facing challenges in the areas of staffing and training.

Turning now to the 7-year reassessment requirement, we considered operators' experiences in relation to the industry consensus standards that basically call for reassessments at 5, 10- 15, or 20-year intervals. We have also considered whether the operators expect to be able to obtain the resources necessary to implement the requirement. Most of the operators that we contacted told us that, if the 7-year requirement were not in place, the conditions that they identified would lead them to reassess their pipelines at 10, 15, or 20 years following the industry consensus standards.

For pipelines operating under higher stress, the 7-year reassessment requirement represents an approximately midpoint between the 5 and 10-year industry reassessment requirements for these pipelines. However, while the standard requires a five-year interval if all repairs are not made, PHMSA's regulations require that these repairs be made, making the 5-year interval less relevant.

Operators pointed out that reassessing their pipelines in 7 rather than 10 years creates additional costs without equivalent improvements in safety, and that these costs will eventually be passed on to customers. Most operators told us the 7-year requirement is also conservative for pipelines that operate under lower stress. This is especially true for local distribution companies. Most we spoke with reported finding conditions that would necessitate another assessment in 15 to 20 years in the absence of the 7-year requirement.

Operators view the assessment as valuable for public safety. However, those operators prefer a risk-based requirement based on engineering standards. This approach would be consistent with the overall thrust of the integrity management program. Many noted that reassessing pipeline segments with no defects every 7 years, in addition to not enhancing of safety, takes resources away from other riskier segments that require attention.

Operators and inspection contractors we contacted told us that the services and tools needed to conduct reassessments will likely be available to most operators, including during the overlap period from 2010 through 2012, where some baseline assessment activity and reassessments will happen during the same time. Some operators told us that they had already signed long-term contracts to lock in the services that they need.

Another issue is whether natural gas supplies could be interrupted and affects the energy market during years when a large number of assessments and reassessments occur if operators have to reduce pressure in their pipelines to conduct assessments and make repairs.

Finally, we reported in 2004 that PHMSA did not have a clear and comprehensive enforcement strategy. In response, PHMSA adopted a strategy last year that is focused on using risk-based enforcement, increasing knowledge and accountability, and improving its own enforcement activities. Our preliminary review is that this strategy is responsive to the concerns we raised.

Mr. Chairman, this concludes my statement. I would be happy to answer any questions.

[The prepared statement of Katherine Siggerud follows:]

PREPARED STATEMENT OF KATHERINE SIGGERUD, DIRECTOR, PHYSICAL INFRASTRUCTURE ISSUES, U.S. GOVERNMENT ACCOUNTABILITY OFFICE

United States Government Accountability Office

GAO

Testimony

Before the Subcommittee on Energy and Air Quality, Committee on Energy and Commerce, House of Representatives

For Release on Delivery
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GAS PIPELINE SAFETY

Preliminary Observations on the Implementation of the Integrity Management Program

Statement of Katherine Siggerud, Director
Physical Infrastructure Issues

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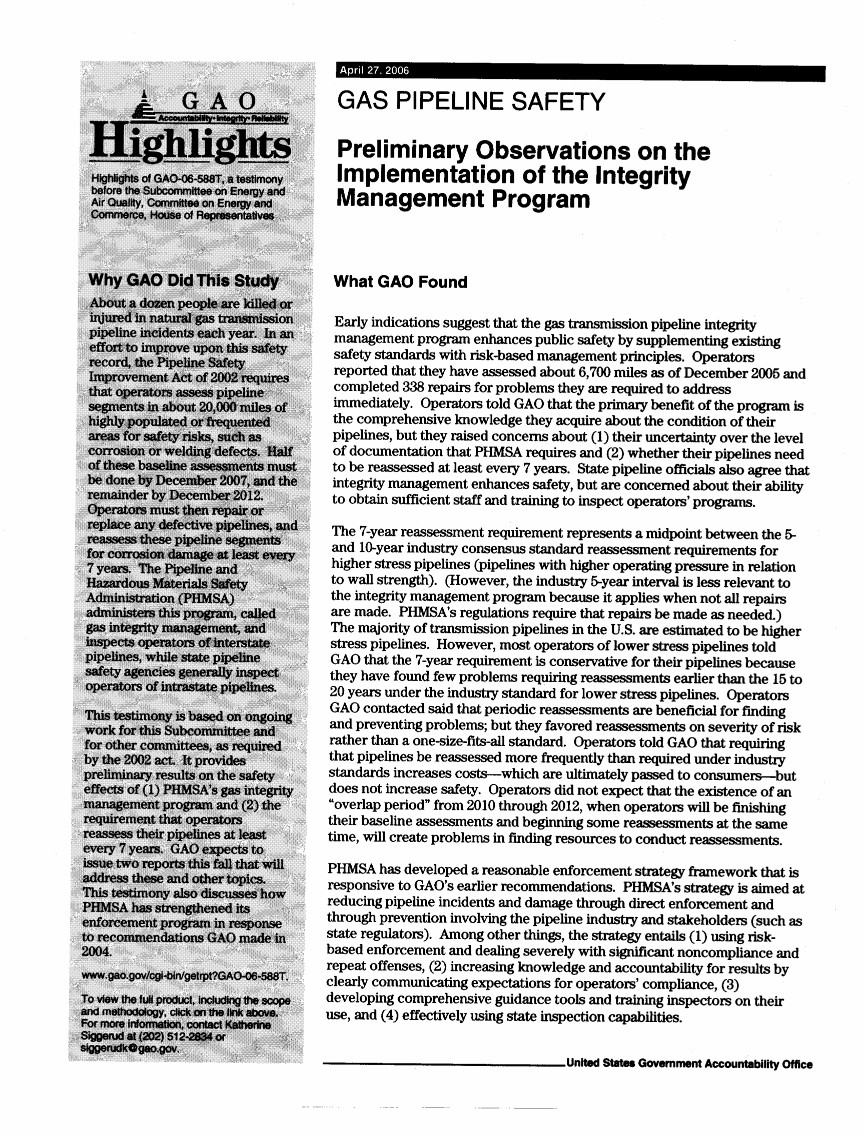
GAO-06-588T



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Highlights

Highlights of GAO-06-588T, a testimony before the Subcommittee on Energy and Air Quality, Committee on Energy and Commerce, House of Representatives

Why GAO Did This Study

About a dozen people are killed or injured in natural gas transmission pipeline incidents each year. In an effort to improve upon this safety record, the Pipeline Safety Improvement Act of 2002 requires that operators assess pipeline segments in about 20,000 miles of highly populated or frequented areas for safety risks, such as corrosion or welding defects. Half of these baseline assessments must be done by December 2007, and the remainder by December 2012. Operators must then repair or replace any defective pipelines, and reassess these pipeline segments for corrosion damage at least every 7 years. The Pipeline and Hazardous Materials Safety Administration (PHMSA) administers this program, called gas integrity management, and inspects operators of interstate pipelines, while state pipeline safety agencies generally inspect operators of intrastate pipelines.

This testimony is based on ongoing work for this Subcommittee and for other committees, as required by the 2002 act. It provides preliminary results on the safety effects of (1) PHMSA's gas integrity management program and (2) the requirement that operators reassess their pipelines at least every 7 years. GAO expects to issue two reports this fall that will address these and other topics. This testimony also discusses how PHMSA has strengthened its enforcement program in response to recommendations GAO made in 2004.

www.gao.gov/cgi-bin/getrpt?GAO-06-588T.

To view the full product, including the scope and methodology, click on the link above. For more information, contact Katherine Siggerud at (202) 512-2834 or siggerudk@gao.gov.

April 27, 2006

GAS PIPELINE SAFETY

Preliminary Observations on the Implementation of the Integrity Management Program

What GAO Found

Early indications suggest that the gas transmission pipeline integrity management program enhances public safety by supplementing existing safety standards with risk-based management principles. Operators reported that they have assessed about 6,700 miles as of December 2005 and completed 338 repairs for problems they are required to address immediately. Operators told GAO that the primary benefit of the program is the comprehensive knowledge they acquire about the condition of their pipelines, but they raised concerns about (1) their uncertainty over the level of documentation that PHMSA requires and (2) whether their pipelines need to be reassessed at least every 7 years. State pipeline officials also agree that integrity management enhances safety, but are concerned about their ability to obtain sufficient staff and training to inspect operators' programs.

The 7-year reassessment requirement represents a midpoint between the 5- and 10-year industry consensus standard reassessment requirements for higher stress pipelines (pipelines with higher operating pressure in relation to wall strength). (However, the industry 5-year interval is less relevant to the integrity management program because it applies when not all repairs are made. PHMSA's regulations require that repairs be made as needed.) The majority of transmission pipelines in the U.S. are estimated to be higher stress pipelines. However, most operators of lower stress pipelines told GAO that the 7-year requirement is conservative for their pipelines because they have found few problems requiring reassessments earlier than the 15 to 20 years under the industry standard for lower stress pipelines. Operators GAO contacted said that periodic reassessments are beneficial for finding and preventing problems; but they favored reassessments on severity of risk rather than a one-size-fits-all standard. Operators told GAO that requiring that pipelines be reassessed more frequently than required under industry standards increases costs—which are ultimately passed to consumers—but does not increase safety. Operators did not expect that the existence of an "overlap period" from 2010 through 2012, when operators will be finishing their baseline assessments and beginning some reassessments at the same time, will create problems in finding resources to conduct reassessments.

PHMSA has developed a reasonable enforcement strategy framework that is responsive to GAO's earlier recommendations. PHMSA's strategy is aimed at reducing pipeline incidents and damage through direct enforcement and through prevention involving the pipeline industry and stakeholders (such as state regulators). Among other things, the strategy entails (1) using risk-based enforcement and dealing severely with significant noncompliance and repeat offenses, (2) increasing knowledge and accountability for results by clearly communicating expectations for operators' compliance, (3) developing comprehensive guidance tools and training inspectors on their use, and (4) effectively using state inspection capabilities.

United States Government Accountability Office

Mr. Chairman and Members of the Subcommittee:

We appreciate the opportunity to participate in this oversight hearing on the Pipeline Safety Improvement Act of 2002. The act strengthens federal pipeline safety programs and enforcement, state oversight of pipeline operators, and public education on pipeline safety. The information that we and others will provide today should help the Congress as it prepares to reauthorize pipeline safety programs.

My statement is based on the preliminary results of our ongoing work for this Subcommittee and others. As directed by the 2002 act, we are assessing the effects on safety stemming from (1) the Pipeline and Hazardous Materials Safety Administration's (PHMSA) integrity management program for gas transmission pipelines and (2) the requirement that pipeline operators reassess their natural gas pipelines for certain safety risks at least every 7 years.[1] In addition, I would also like to briefly touch on how PHMSA has acted to strengthen its enforcement program. I testified on PHMSA's enforcement program before this Subcommittee almost 2 years ago,[2] and believe that this is a good opportunity to update you on some positive accomplishments.

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[1] Under integrity management, operators systematically assess the portions of their pipelines that are in highly populated or frequented areas (such as parks) for safety risks. Although the gas integrity management program applies to natural, toxic, and corrosive gases, the overwhelming majority of gas pipelines in the United States carry natural gas. Our work therefore focuses on natural gas. Transmission pipelines transport gas products from sources to communities and are primarily interstate. Distribution pipelines (local distribution companies) that carry natural gas to ultimate users, such as homes, are not subject to the 2002 act.

[2] GAO, *Pipeline Safety: Preliminary Information on the Office of Pipeline Safety's Actions to Strengthen Its Enforcement Program,* GAO-04-985T (Washington, D.C.: July 20, 2004) and GAO, *Pipeline Safety: Management of the Office of Pipeline Safety's Enforcement Program Needs Further Strengthening,* GAO-04-801 (Washington, D.C.: July 23, 2004).

Our work is based on our review of laws, regulations, and other PHMSA guidance, as well as discussions with a broad range of stakeholders, including industry trade associations, pipeline safety advocate groups, state pipeline agencies, pipeline inspection contractors, and consensus standards organizations.[3] In addition, we surveyed the 47 state pipeline agencies responsible for inspecting intrastate gas transmission pipeline operators on their plans for conducting inspections of operators' integrity management programs.[4] We also contacted 41 pipeline operators about the matters that I will discuss today. We chose operators for which integrity management could have the greatest impact, all else being equal: larger and smaller operators with the highest proportion of pipelines in highly populated or frequented areas to total miles of pipeline. These operators represent about 60 percent of the miles of pipeline assessed to date. We relied on pipeline operators' professional judgment in reporting on the conditions that they found during their assessments of safety risks. The information that we obtained from the 41 operators is not necessarily generalizable to all operators. As part of our work, we assessed the internal controls and the reliability of the data elements needed for this engagement, and we determined that the data elements were sufficiently reliable for our purposes. We performed our work in accordance with generally accepted government auditing standards from August 2005 to April 2006.

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[3] Standards are technical specifications that pertain to products and processes, such as the size, strength, or technical performance of a product. National consensus standards are developed by standard-setting entities on the basis of an industry consensus. PHMSA's regulations incorporate standards, including reassessment standards, developed by the American Society of Mechanical Engineers: *Managing the System Integrity of Gas Pipelines* (ASME B31.8S-2004) and the National Association of Corrosion Engineers: *Standard Recommended Practice -Pipeline External Corrosion Direct Assessment* (NACE RP0502-2002).

[4] For the purpose of this statement, we treat the District of Columbia as a state pipeline agency.

In summary:

- Implementation of integrity management is in its early stages as PHMSA's regulations were finalized in 2004. Early indications suggest that the gas integrity management program has enhanced public safety by requiring that operators identify and address the risks to pipeline segments located in areas that are most likely to affect public safety. Operators believe that the primary benefit of the program is the comprehensive knowledge they must acquire about the condition of their pipelines. However, operators have raised concerns about (1) their uncertainty over the level of documentation required by the program and (2) whether the requirement to reassess their pipelines at least every 7 years contributes to increased safety. PHMSA's initial inspections of 13 interstate operators' integrity management programs have shown that operators are doing well in assessing their pipelines and making repairs but that they need to better document their management practices and decisions. Most state pipeline officials reported that they have started or will start integrity management inspections of intrastate operators this year. While state officials reported that they generally agree that integrity management enhances public safety, most are facing challenges in the areas of staffing and training.

- Overall, pipeline operators have reported to PHMSA that, in the 6,700 miles of pipeline in highly populated or frequented areas they have assessed, they have found 338 problems that required immediate repair or replacement[5]—about 1 problem every 20 miles, on average. The 41 operators that we contacted—which represent about 60 percent of the 6,700 miles assessed so far—told us that, if the 7-year requirement were not in place, they would reassess the pipeline segments located in highly populated or frequented areas every 10, 15, or 20 years following industry consensus standards.[6] The 7-year reassessment requirement reflects a midpoint in relation to industry standards for pipelines operating under higher stress (pipelines with higher operating pressure in relation to wall strength) where as the industry standard for reassessments is 10 years or less. (The industry standard requires that pipelines be reassessed at least every 5 years if all repairs are not made. PHMSA's regulations require that repairs be made as necessary.) However, operators told us that the 7-year reassessment requirement is conservative for pipelines operating under lower stress, where as the industry reassessment standard can extend to 15 to 20 years. The large majority of transmission pipelines in the U.S. are estimated to be higher-stress pipelines, based on information from industry associations. Most operators of lower-stress pipelines (21 of the 26 we contacted) told us that they found few problems during baseline assessments that would require reassessments before 15 or 20 years. Operators that we contacted believed that periodic reassessments of their pipelines would be beneficial in finding and preventing problems. However, they favored conducting reassessments based on severity of risk rather than applying a one-size-fits-all standard. Operators told us that requiring that pipelines be reassessed more frequently than required under industry standards increases costs—which are ultimately passed to consumers—but does not increase safety. Operators did not expect that the existence of an "overlap period" from 2010 through 2012, when operators will be completing baseline assessments and beginning some reassessments at the same time, would create problems in finding resources to conduct reassessments.[7] The existence of an overlap had been an industry concern while the 2002 act was being debated.

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[5] Operators have reported that about 20,000 miles of pipeline are located in highly populated or frequented areas. Operators are required to make immediate repairs to their pipelines if they (1) determine the remaining strength of the pipe shows a predicted failure pressure of less than or equal to 1.1 times the maximum allowable operating pressure; (2) identify a dent that has any indication of metal loss, cracking, or a stress riser; or (3) determine, in their judgment, the assessment results require immediate action. Stress risers are corrosion, gouges, or cracks within or between dents.

[6] The standards have been accepted by the American National Standards Institute, a private, non-profit organization whose mission is to promote and facilitate voluntary consensus standards and promote their integrity. The Institute does not approve the technical merits of proposed national standards. Rather it ensures that proposed national standards are developed in an environment of openness, balance, consensus, and due process.

- PHMSA has developed a reasonable enforcement strategy framework that is responsive to concerns we raised in 2004 that PHMSA had not incorporated into its enforcement strategy key features of effective program management—clear program goals, a well- defined strategy for achieving those goals, and performance measures linked to the program goals. PHMSA's recently developed strategy is aimed at reducing pipeline incidents and damage through both direct enforcement and prevention. The strategy entails, among other things, (1) using risk-based enforcement that clearly reflects potential risk and seriousness and dealing severely with operators' significant noncompliance and repeat offenses; (2) increasing knowledge of and accountability for results by clearly communicating expectations for operators' compliance; (3) developing comprehensive guidance tools, along with training inspectors on their use; and (4) effectively using state inspection capabilities.

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[7] Under the 2002 act, operators have until 2012 to complete their baseline assessments. However, under the 7-year reassessment requirement, operators that started their baseline assessments in 2003 would then need to reassess those pipeline segments in 2010.

Background

On average, about 3 people have died and about 8 people have been injured annually over the last 10 years in natural gas transmission pipeline incidents. The number of incidents has increased from 77 in 1996 to 122 in 2004 and 200 in 2005, primarily due to the greater frequency of property damage.[8] Much of this increase may be attributed to the rise in the price of gas (which has the effect of lowering the reporting threshold) over the past several years and to damage as a result of hurricanes in 2005.

As a means of enhancing the security and safety of gas pipelines, the 2002 act included an integrity management structure that, in part, requires operators of gas transmission pipelines to systematically assess for safety risks the portions of their pipelines located in highly populated or frequently used areas, such as parks. Safety risks include corrosion, welding defects and failures, third-party damage (e.g., from excavation equipment), land movement, and incorrect operation. The act requires that operators perform these assessments (called baseline assessments) on half of the pipeline mileage in highly populated or frequented areas by December 2007 and the remainder by December 2012. Those pipeline segments potentially facing the greatest risks are to be assessed first. Operators must then repair or replace any defective pipelines. Performing this form of risk-based assessment is seen by many as having a greater potential to improve safety than focusing on compliance with safety standards regardless of the threat to pipeline safety.

The act further provides that pipeline segments in highly populated or frequented areas must be reassessed for safety risks at least every 7 years.

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[8] An incident, for PHMSA reporting purposes, involves a death; injury requiring hospitalization; or property damage, including any loss of natural gas during an incident, of $50,000 or more.

PHMSA's regulations implemented the act by requiring that operators reassess their pipelines for corrosion damage every 7 years using an assessment technique called confirmatory direct assessment.[9] Under these regulations, and mostly consistent with industry national consensus standards,[10] operators must also reassess their pipeline segments for safety risks at least every 10, 15, or 20 years, depending on the pressure under which the pipeline segments are operated and the condition of the pipeline.

There are about 900 operators of about 300,000 miles of gas transmission and gathering pipelines in the United States. As of December 2005, according to PHMSA, 429 of these operators reported that about 20,000 miles of their pipelines are located in highly populated or frequented areas (about 7 percent of all transmission pipeline miles). Operators reported that they had as many as about 1,600 miles and as few as 0.02 miles of pipeline in these areas.

PHMSA, within the Department of Transportation, administers the national regulatory program to ensure the safe transportation of gas and hazardous liquids (e.g., oil, gasoline, and anhydrous ammonia) by pipeline. The agency attempts to ensure the safe operation of pipelines through regulation, national consensus standards, research, education (e.g., to prevent excavation-related damage), oversight of the industry through inspections, and enforcement when safety problems are found. In general, PHMSA retains full responsibility for inspecting and enforcing regulations on interstate pipelines but certifies states to perform these functions for intrastate pipelines. PHMSA employs about 165 staff in its pipeline safety program, about half of whom are pipeline inspectors who inspect gas and hazardous liquid pipelines under integrity management and other more traditional compliance programs. Nine PHMSA inspectors are currently devoted to the gas integrity management program. State pipeline agencies have about 325 inspectors, about 100 of which are currently able to perform integrity management inspections of intrastate gas transmission pipeline operators in 47 states.

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[9] Confirmatory direct assessment allows for less extensive use of testing methods and is meant to provide assurance that drastic damage is not taking place. Confirmatory direct assessment allows an operator to obtain interim results until it performs a full reassessment.

[10] As discussed earlier, PHMSA's regulations do not provide for the 5-year reassessment interval that are contained in the industry national consensus standards.

Early Indications Suggest that Gas Integrity Management Enhances Public Safety, but Operators and States Raise Some Concerns About Implementation

While the gas integrity management program is still being implemented, early indications suggest that it enhances public safety by supplementing existing safety standards with risk-based management principles. Prior to the integrity management program, there were, and still are, minimum safety standards that operators must meet for the design, construction, testing, inspection, operation, and maintenance of gas transmission pipelines. These standards apply equally to all pipelines and provide the public with a basic level of protection from pipeline failures. However, minimum standards do not require operators to identify and address risks that are specific to their pipelines, nor do they require operators to assess the integrity of their pipelines. While some operators have assessed the integrity of some of their pipelines, others have not. Consequently, some pipelines have operated for 40 or more years with no assessment. The gas integrity management requirements, finalized in 2004, go beyond the existing safety standards by requiring operators, regardless of size, to routinely assess pipelines in highly populated or frequented areas for specific threats, to take action to mitigate the threats, and to document management practices and decision-making processes.

Representatives from the pipeline industry, safety advocate groups, state pipeline agencies, and operators we have contacted agree that the integrity management program enhances public safety. Some operators noted that, although the program's requirements can be costly and time consuming to implement, the benefits to date are worth the costs. The primary benefit identified was the comprehensive knowledge the program requires all operators to have of their pipeline systems. For example, under integrity management, operators must gather and analyze information about their pipelines in highly populated or frequented areas to get a complete picture of the condition of those lines. This includes developing maps of the pipeline system and gathering information on corrosion protection, exposed pipeline, threats from excavation or other third-party damage, and the installation of automatic shut-off valves. Another benefit cited was improved communications within the company. Investigations of pipeline incidents have shown that, in some cases, an operator possessed information that could have prevented an incident but had not shared it with employees who needed it most. Integrity management requires operators to pull together pipeline data from various sources within the company to identify threats to the pipelines, leading to more interaction among different departments within pipeline companies. Finally, integrity management focuses operator resources on those areas where an incident could have the greatest impact.

While industry and operator representatives have provided examples of the early benefits of integrity management, operators must report semiannually on performance measures that should quantitatively demonstrate the impact of the program over time. These measures include the total mileage of pipelines and the mileage of pipelines assessed in highly populated or frequented areas, as well as the number of repairs made and leaks, failures, and incidents identified in these areas. In the 2 years that operators have reported the results of integrity management, they have assessed about 6,700 miles of their 20,000 miles of pipelines located in highly populated or frequented areas, and they have completed 338 repairs that were immediately required and another 998 repairs that were less urgent. While it is not possible to determine how many of these needed repairs would have been identified without integrity management, it is clear that the requirement to routinely assess pipelines enables operators to identify problems that may otherwise go undetected. For example, one operator told us that it had complied with all the minimum safety standards on its pipeline, and the pipeline appeared to be in good condition. The operator then assessed the condition of a segment of the pipeline under its integrity management program and found a serious problem, causing it to shut the line down for immediate repair.

One of the most frequently cited concerns by the 41 operators we contacted was the uncertainty about the level of documentation needed to support their gas integrity management programs. PHMSA requires operators to develop an integrity management program and provides a broad framework for the elements that should be included in the program. Each operator must develop and document specific policies and procedures to demonstrate its commitment to compliance with and implementation of the integrity management requirements. In addition, an operator must document any decisions made related to integrity management. For example, an operator must document how it identified the threats to its pipeline in highly populated or frequented areas and who was involved in identifying the threats, their qualifications, and the data they used. While the operators we contacted agreed with the need to document their policies and procedures, some said that the detailed documentation required for every decision is very time consuming and does not contribute to the safety of pipeline operations. Moreover, they are concerned that they will not know if they have enough documentation until their program has been inspected. After conducting 13 inspections, PHMSA found that, while interstate operators are doing well in conducting assessments and making the identified repairs, they are having difficulty overall in the development and documentation of their management processes. Another concern raised by most of the operators is the requirement to reassess their pipelines at least every 7 years. I will discuss the 7-year reassessment requirement in more detail shortly.

In response to our survey, most state officials indicated that the two most challenging areas for them as they begin implementing gas integrity management inspections are staffing and training. While most state agencies currently have at least two inspectors that can perform inspections of operators' integrity management programs, some state pipeline officials responded that they do not have enough inspectors for the increased workload and/or their inspectors have not completed the training required by PHMSA. To ensure that inspectors have the technical expertise to conduct integrity management inspections, including evaluating operators' processes and decisions, PHMSA requires inspectors to complete 4 classroom and 6 computer-based courses, totaling about 19 days of training. Three of the classroom courses are part of PHMSA's core training for all inspectors and are generally offered annually. The fourth course—a new course that PHMSA established for integrity management—was made available to two inspectors from each state in 2005 and is now offered when there is sufficient demand. The computer-based courses were made available to the states starting in February 2005. While the state officials we spoke with agree that the training is necessary, they are concerned about the amount of time it takes to complete the required training and the limited availability of the classroom training. We will continue to follow up with state agencies about how these challenges will affect their oversight activities.

I am pleased to report that in response to our 2002 recommendation,[11] PHMSA has been working to improve its communication with states about their role in overseeing integrity management programs. For example, PHMSA's efforts include (1) inviting state inspectors to attend federal inspections, (2) creating a Web site containing inspection information, and (3) providing a series of updates through the National Association of Pipeline Safety Representatives. Results from the survey of state pipeline agencies (with most of the states responding thus far) show that the majority of state agencies believe that communication from PHMSA has been very or extremely useful in helping them understand their roles and responsibilities in conducting integrity management inspections.[12]

7-Year Reassessment Requirement May be Appropriate for Some Operators but Conservative for Others

Nationwide, pipeline operators reported to PHMSA that they have found, on average, about one problem requiring immediate repair or replacement for every 20 miles of pipeline assessed in highly populated or frequented areas. Operators we contacted recognize the benefits of reassessments; however, almost all would prefer following the industry national consensus standards that use safety risk, rather than a prescribed term, for determining when to reassess their pipelines. Most operators expect to be able to acquire the services and tools needed to conduct these

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[11] GAO, *Pipeline Safety and Security: Improved Workforce Planning and Communication Needed,* GAO-02-785 (Washington, D.C.: Aug. 26, 2002).

[12] Of the 46 state agencies that responded, three state agencies indicated that PHMSA information was extremely useful, 23 state agencies said the information was very useful, 9 state agencies said it was moderately useful, 5 said it was somewhat useful, 1 said it was not useful, and 5 had no opinion.

reassessments, including during the overlap period when they are starting to reassess pipeline segments while completing baseline assessments.

Operators Favor a Risk-based, Rather than a One-Size-Fits-All, Reassessment Standard

As discussed earlier, as of December 2005, operators nationwide have notified PHMSA of 338 problems that required immediate repair in the 6,700 miles in highly populated or frequented areas that they have assessed—about one immediate repair required for every 20 miles of pipeline assessed in highly populated or frequented areas.[13] The number of immediate repairs may be due, in part, to some operators systematically assessing their pipelines for the first time as a result of the 2002 act.

We contacted 41 transmission operators and local distribution companies about their assessment activities. These operators represent about 60 percent of the 6,700 miles assessed nationwide. Of these, 38 have begun assessments and 32 (84 percent) told us that they found few safety problems that required reducing pressure and performing immediate repairs during baseline assessments. These assessments covered (1) about 4,100 miles of pipeline in highly populated or frequented areas and (2) about 30,000 miles outside of these areas.[14] (See fig. 1.) Twenty-five of these 38 operators reported finding pipelines in good condition and free of major defects, requiring only minor repairs or recoating. Seven of these operators found two or fewer problems per 100 miles that require

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[13] Most operators found no or few problems and a handful found more than 10 problems overall requiring immediate repair. We hope to portray these results when we report to this Subcommittee and others this fall.

[14] For example, pipeline operators told us that, when they run an in-line inspection tool through a pipeline, they do not collect data solely within the boundary of the highly populated or frequented area if the insertion and retrieval points for the tool extend beyond the highly populated or frequented area. Rather, they gather information on the pipeline's condition for the entire distance between the insertion and retrieval points because, in doing so, they gather additional insights into the condition of their pipeline.

immediate repairs. Finally, six operators found five or more immediate repairs per 100 miles assessed.[15] Operators nonetheless found these assessments valuable in determining the condition of their pipelines and finding damage. The large proportion of these operators reporting that they found no or few problems requiring immediate repair is encouraging if they represent assessments of their segments facing the greatest risk, as required by the 2002 act.

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[15] In figure 1, the results for operator Hi12 show a greater number of problems requiring immediate repair (per 100 miles assessed) because it has assessed 11 miles and found 2 of these problems. The other two operators showing the largest number of problems per 100 miles requiring immediate repair, Lo25 and Lo26, have assessed 77 miles and 370 miles, respectively.

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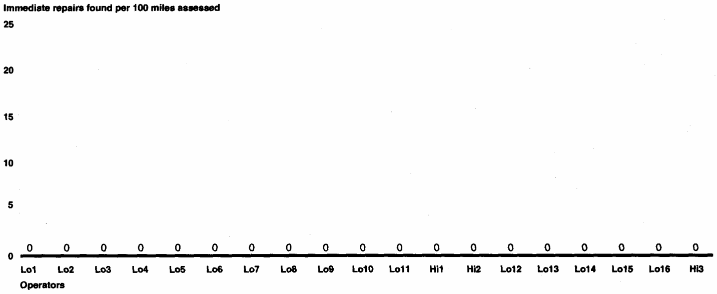
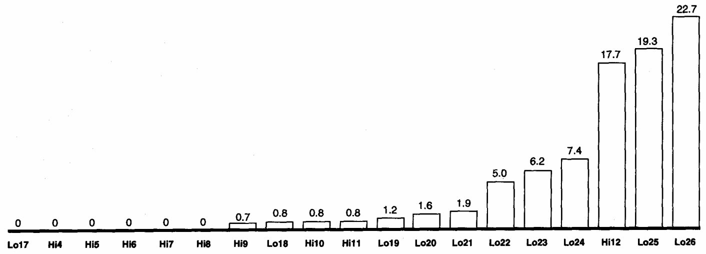
Figure 1: Number of Immediate Repairs Needed as Found During Baseline Assessments



Source: GAO interviews with operators.



Note: The Hi and Lo prefixes to the operator designations denote higher stress and lower stress pipelines, respectively. To prevent distortion, we excluded 3 of the 41 operators we contacted because they had assessed 0 miles of pipeline to date. This figure includes the immediate repairs for pipeline located both inside and outside of highly populated or frequented areas.

The results for operator Hi12 show a greater number of problems requiring immediate repair (per 100 miles assessed) because it has assessed 11 miles and found 2 of these problems. The other two operators showing the largest number of problems per 100 miles requiring immediate repair, Lo25 and Lo26 have assessed 77 miles and 370 miles, respectively.

Of the 38 operators that have begun assessment activities, 22 have calculated reassessment intervals.[16] These operators indicated that based on the conditions that they identified during baseline assessments; they could reassess their pipelines at intervals of 10, 15, or 20 years – as allowed by industry consensus standards[17] – if the 7-year reassessment requirement were not in place. In some cases, operators chose to reassess their pipelines at intervals shorter than the industry standards based on their own discretion. These baseline assessment findings suggest that overall—at least for the operators we contacted—the 7-year requirement is conservative.

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[16] The other 16 operators either (1) have not calculated reassessment intervals; (2) do not intend to, given the prescriptive federal (7 years) or state (5 years in Texas) reassessment requirements; or (3) did not supply us information on their reassessment intervals.

[17] As discussed earlier, the development of these standards met the American National Standards Institute's requirements for openness, balance, consensus, and due process.

The 7-year reassessment interval represents an approximate midpoint between the 5- and 10-year industry reassessment requirements for pipelines operating under higher-stress. (The industry standard requires that pipelines be reassessed at least every 5 years if all repairs are not made. PHMSA's regulations require that repairs be made as necessary.) Higher-stress transmission pipelines are typically those that transport natural gas across the country from a gathering area to a local distribution company. Operators pointed out that reassessing their pipelines in 7 rather than 10 years creates additional costs without an equivalent gain in safety; that is, if the 7-year interval requirement were not in place they would not reassess their pipelines for another 3 years consistent with industry standards. Operators added that the costs of the more frequent reassessments will eventually be passed on to customers. PHMSA does not collect information in such a way that would allow us to readily estimate the percentage of all pipeline miles in highly populated or frequented areas that operate under higher pressure. In the aggregate, the 41 operators that we contacted told us that more than three-fourths of their pipeline mileage in highly populated or frequented areas is operated under higher pressure. Finally, industry data suggest that in the neighborhood of 250,000 miles of the 300,000 miles (over 80 percent) of all transmission pipelines nationwide may operate under higher pressure.

Some operators told us that the 7-year reassessment requirement is conservative for pipelines that operate under lower stress. This is especially true for local distribution companies that use their transmission lines mainly to transport natural gas under lower pressure for several miles from larger cross-country lines in order to feed smaller distribution lines. They pointed out, for example, that in a lower-pressure environment, pipelines tend to leak rather than rupture. Leaks involve controlled, slow emissions that typically pose little damage or risk to public safety. Twenty-one of the 26 lower stress operators (most of which are local distribution companies) we contacted that have begun assessments reported finding few, if any, conditions during baseline assessments that would require immediate repair. (See fig. 1 and accompanying note.) As a result, if the 7-year requirement did not exist, these local distribution companies would likely reassess every 15 to 20 years, following industry consensus standards. Some of these operators pointed out that third-party damage poses the greatest threat to their systems. Operators added that third-party damage, such as dents caused by excavation, can happen at any time and that prevention and mitigation measures are the best ways to address it.[18]

Operators viewed a risk-based reassessment requirement, such as in the consensus standard, as valuable for public safety. Operators of both higher-stress and lower-stress pipelines indicated a preference for a risk-based reassessment requirement based on engineering standards rather than a prescriptive one-size-fits-all standard.[19] In addition, a risk-based reassessment standard would be consistent with the overall thrust of the integrity management program. Some operators noted that reassessing

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[18] Prevention and mitigation measures include one-call programs, proper marking of the pipeline's location, inspection by air, and public education programs. In one-call programs, persons who want to dig in an area contact a clearinghouse. The clearinghouse notifies pipeline operators and others that someone is going to be digging near the pipeline so that the operator can mark the pipeline's location prior to the digging work.

[19] On a related note, the Congress expressed a general preference for technical standards developed by consensus bodies over agency-unique standards in the National Technology Transfer and Advancement Act of 1995.

pipeline segments with few defects every 7 years takes resources away from riskier segments that require more attention. While PHMSA's regulations require that pipeline segments be reassessed only for corrosion problems at least every 7 years using the less intensive assessment technique of confirmatory direct assessment, some operators point out that it has not worked out that way. They told us that, if they are going to the effort of assessing pipeline segments to meet the 7-year reassessment requirement, they will typically use more extensive testing—both for corrosion and other problems—than required, because doing so will provide more comprehensive information. Thus, in most cases, operators plan to reassess their pipelines by using the more extensive in-line inspections or direct assessment for problems in addition to corrosion sooner than required under PHMSA's rules.[20]

Finally, operators are required by PHMSA to take actions in addition to periodically reassessing their pipelines. Operators must, on an ongoing basis, evaluate their pipelines by integrating operational data with other information, including assessment data and risk assessment information, to assure the integrity of their pipelines. Operators will use the results from the evaluation to identify and remediate specific pipeline threats and associated risks.

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[20] Direct assessment is a four-step procedure used to identify corrosion and other pipeline defects. First, operators analyze information about the physical characteristics of a pipeline, such as coating, soil moisture, and past leaks. Second, operators use one or more tools to examine the pipeline through the soil in areas identified in the first step. Third, operators use the results of the above-ground examination to dig holes in intervals along the pipeline to examine suspected pipeline problem areas. Finally, operators integrate and analyze information gathered during the three previous steps to determine when additional digging is necessary and how often pipeline segments should be reassessed.

Services and Tools Are Likely to be Available for Reassessments

Thirty-four of the 41 operators and 4 inspection contractors and 1 association we contacted (85 percent) told us that the services and tools needed to conduct periodic reassessments will likely be available to most operators.[21] All but one of the operators reported that they plan to rely on contractors to conduct all or a portion of their reassessments, and eight of the 41 operators have signed, or would like to sign, long-term contracts that extend contractor services through a number of years. However, few have scheduled reassessments with contractors, as reassessments will take place several years in the future, and operators are concentrating on baseline assessments.

Thirty of the 38 operators (79 percent) that reported both baseline and reassessment schedules to us said that they primarily plan to use in-line inspection or direct assessment to reassess segments of their pipelines located in highly populated or frequented areas. In-line inspection contractors that we contacted report that there is capacity within the industry to meet current and future operator demands. Unlike the in-line inspection method, which is an established practice that 25 of 41 operators have used on their pipelines at least once prior to the integrity management program, the direct assessment method is new to both contractors and operators. Direct assessment contractors told us that there is limited expertise in this field, and one contractor said that newer contractors coming into the market to meet demand may not be qualified. The operators planning to use direct assessment for their pipelines are generally local distribution companies with smaller diameter pipelines that cannot accommodate in-line inspection tools.[22]

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[21] To prepare for this hearing, we contacted the Inline Inspection Association, two companies offering in-line inspection services, and two companies offering direct assessment services.

An industry concern about the 7-year reassessment requirement is that operators will be required to conduct reassessments starting in 2010 while they are still in the 10-year period (2003-2012) for conducting baseline assessments. Industry is concerned that this could create a spike in demand for contractor services resulting from an overlap of assessments and reassessments from 2010 through 2012, and operators would have to compete for the limited number of contractors to carry out both. The industry was worried that operators might not be able to meet the reassessment requirement and that it was unnecessarily burdensome.[23] However, the information provided by the operators that we contacted does not suggest a spike and because baseline assessment activity should decrease as they begin to conduct reassessments. (See fig. 2.) Operators predict that they will have conducted a large number of baseline assessments between 2005 and 2007 in order to meet the statutory deadline for completing at least half of their baseline assessments by December 2007 –two years before the predicted overlap.

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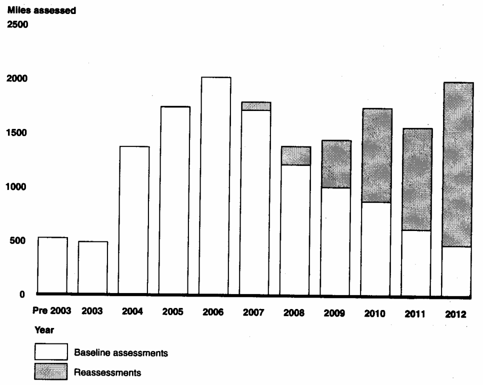
[22] According to industry estimates, 35 percent of all local distribution company pipelines (as measured in miles likely to be located in highly populated areas) cannot accommodate an in-line inspection tool, compared to only about 4 percent of transmission operators' pipelines.

Figure 2: Operators' Planned Baseline Assessment and Reassessment Schedules



Source: GAO.

Note: This figure shows the baseline assessments conducted, or planned to be conducted, as well as the reassessments that are planned in highly populated or frequented areas for the 38 of 41 operators we contacted. Five operators did not report their reassessment plans.

There has also been a concern about whether baseline assessments and reassessments would affect the natural-gas supply if pipelines are taken out of service or operate at reduced pressure when repairs are being made. We are addressing this issue and will report on it in the fall.

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[23] The 2002 act allows operators to request a waiver from conducting reassessments when inspection tools are not available and when operators need to maintain product supply. PHMSA has not issued guidance on conditions under which it would grant a waiver.

PHMSA Has Developed a Reasonable Framework for Its Enforcement Program

In 2004, we concluded that we could not assess the effectiveness of PHMSA's enforcement strategy because it had not incorporated key features of effective program management—clear program goals, a well-defined strategy for achieving those goals, and performance measures that link to the program goals.[24] In response to our concerns, PHMSA adopted a strategy in August 2005 that focuses on using risk-based enforcement, increasing knowledge of and accountability for results, and improving its own enforcement activities. The strategy also links these efforts to goals to reduce and prevent pipeline incidents and damage, in addition to providing for periodic assessment of results. While we have neither reviewed the revised strategy in depth nor examined how it is being implemented, our preliminary view is that it is a reasonable framework that is responsive to the concerns that we raised in 2004.

PHMSA has established overall goals for its enforcement program to reduce incidents and damage due to operators' noncompliance. PHMSA also recognizes that incident and damage prevention is important, and its strategy includes a goal to influence operators' actions to this end. To meet these goals, PHMSA has developed a multi-pronged strategy that is directed at the pipeline industry and stakeholders (such as state regulators), ensures that its processes make effective use of its resources.

For example, PHMSA's strategy calls for using risk-based enforcement to, among other things, take enforcement actions that clearly reflect potential risk and seriousness and deal severely with significant operator noncompliance and repeat offenses. Second, the strategy calls for increasing knowledge of and accountability for results through such actions as (1) soliciting input from operators, associations, and other stakeholders in developing and refining regulations, inspection protocols, and other guidance; (2) clearly communicating expectations for compliance and sharing lessons learned; and (3) assessing operator and industry compliance performance and making this information available. Third, the strategy, among other things, calls for improving PHMSA's own enforcement activities by developing comprehensive guidance tools, training inspectors on their use, and effectively using state inspection capabilities.

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[24] GAO-04-801.

Finally, to understand the progress being made in encouraging pipeline operators to improve their level of safety and, as a result, reduce accidents and fatalities, PHMSA annually will assess its overall enforcement results as well as various components of the program. Some of the program elements that it may assess are inspection and enforcement processes, such as the completeness and availability of compliance guidance, the presentation of operator and industry performance data, and the quality of inspection documentation and evidence.

Concluding Observations

Our work to date suggests that PHMSA's gas integrity management program should enhance pipeline safety, and operators support it. We have not identified issues that threaten the overall framework of integrity management. We expect to provide additional insights into issues involving state pipeline agency staffing and training and the 7-year reassessment requirement when we report to this Subcommittee and others this fall.

Because the program is in its early phase of implementation, PHMSA is learning how to oversee the program, and operators are learning how to meet its requirements. Similarly, operators are in the early stages of assessing their pipelines for safety problems. This means that the integrity management program will be going through this shakedown period for another year or two as PHMSA and operators continue to gain experience.

Mr. Chairman, this concludes my prepared statement. I would be pleased to respond to any questions that you or the other Members of the Subcommittee might have.

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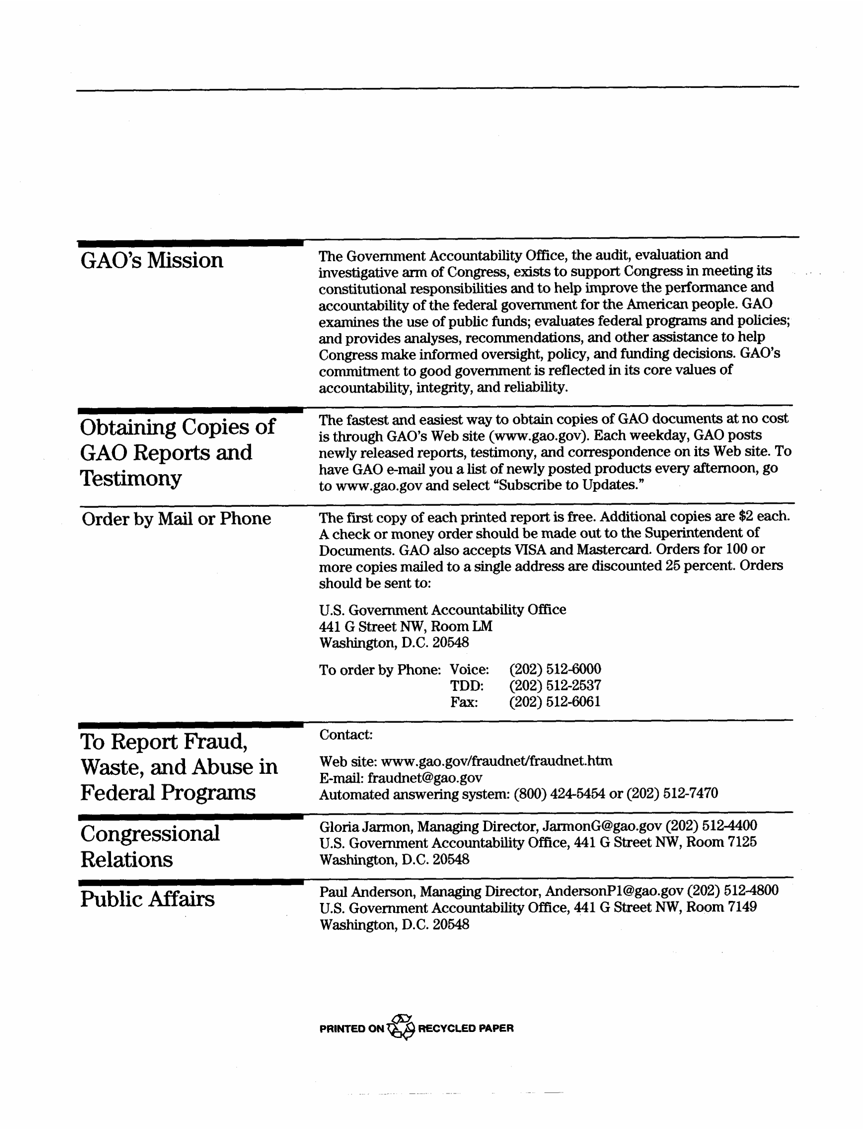

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MR. HALL. All right. I thank you very much.

And at this time, the gentleman from Texas, Mr. Gonzalez, do you wish to make your opening statement or have it put in the record, sir?

MR. GONZALEZ. Put it in the record, thank you very much, Mr. Chairman.

MR. HALL. Without objection, we will do so.

MR. HALL. And we will begin some inquiries here. I guess, Ms. Gerard, I will probably start with you.

Talk to us about how the coordination between your agencies and others have been, including TSA, EPA, and Interior, since the enactment of the Pipeline Safety Improvement Act of 2002. Where do you see any remaining issues, such as response to terrorist threats, emergency waiver authority, and spill response, issues like that, if you would? And gosh, you have 5 minutes to do that in.

MS. GERARD. Coordination with the other Federal agencies has been much improved, especially with agencies responsible for permitting repairs, environmental permits, especially the Department of Interior agencies, EPA, and cooperation is much improved. Also, we work closely with the Federal Energy Regulation Commission on L&G issues, as well as the Coast Guard, which is now a part of DHS. We have a concerted integrated approach, which I believe is more effective.

As to security issues, we work closely with the Department of Homeland Security on, basically, a daily basis. We are supportive of their efforts. They clearly have a lead role in security, and we provide our operational expertise on various aspects of planning when requested.

You asked about oil spill planning, and I think oil spill planning relationships have been fairly constant since the early 1990s and remain good.

MR. HALL. I have other questions, but I think I will recognize Mr. Boucher for his. I believe that we have Members, obviously, that have some personal questions and very descriptive testimony to make inquiries from, and we will get to them.

Mr. Boucher, we will recognize you for 5 minutes or more.

MR. BOUCHER. Well, thank you very much, Mr. Chairman. I particularly appreciate the "more."

Mrs. Gerard, thank you for your testimony this morning.

In my opening statement, I referenced information that I have that, to date, the grants that we had required to be made in the 2002 legislation to assist communities with technical assistance to address a range of pipeline issues have not been made. Is that information correct? And if it is correct, why have the grants not been made, as we required four years ago?

MS. GERARD. Yes, sir, it is correct; we have not made those grants. We have not been successful in requesting funding for the grants. We do realize the importance of the intent and did step out to meet the intent of the law in every way that we could, including improving public education standards, making considerable changes to our website to provide much more specific and localized information in a form that communities could use. We have also hired new staff who are engineers who are focused on solely reaching out to communities and State government and addressing questions that they have personally. We have also made changes to the national pipeline mapping system, which, although we took it off the website after 9/11, we made modifications so that a citizen in a neighborhood could put in a zip code and get information on a 24-hour contact with an operator who they could begin a dialogue with.

MR. BOUCHER. Well, all of those steps sound positive to me, and I would applaud you having taken those steps. And I would assume that you were able to find funding within your general budget in order to finance those particular steps. I would simply encourage you to go back and look within your general budget and try to find money for the rather modest grants that we expected to be made to local governments. Have you gotten any applications from localities for these grants to date?

MS. GERARD. We have not gotten applications. We did hold a public meeting on the subject a year ago December, and we did discuss in public we were specifically seeking advice from stakeholders on what type of criteria that we should use to make those grants. And they looked to the State of Washington, that has a lot of experience in working with stakeholder groups. So I think we have taken steps to prepare to make those grants, but haven't made them due to funding issues.

MR. BOUCHER. Well, all right. I hear the answer. I don't think we anticipated that an appropriation specifically line-itemed for technical assistance grants directed to you would be required for this. It was anticipated that your general budget would be sufficient for that purpose.

Let me move to another subject.

I mentioned, also, in my opening statement the fact that Virginia has had a very successful experience with its excavation damage prevention program. That program is a creature of State law in Virginia, and it is enthusiastically supported by the pipeline industry and also by utilities. It derived from a consensus-based process in which all of the stakeholders shared views and have their concerns acknowledged, and a very successful program arose from that collaborative effort. What model from that successful Virginia experience could we derive for national application, and would it be helpful for us, in the reauthorization of the Pipeline Safety Act, to include some kind of provision? I am not suggesting a complete program outlined in the statute, but some kind of provision that might lead to similar success stories nationwide. Do you have any recommendations for us?

MS. GERARD. We completely agree with you that the Virginia experience is the most perfect model we have seen anywhere in the United States. We have spent a great deal of staff time working with the Common Ground Alliance and other States to highlight the performance that has resulted from the Virginia experience. We do think it would be helpful for the committee, as a focus in reauthorization, to look at the safety improvements and damage reductions that have been achieved in Virginia. And our approach is generally to incentivize States and highlight what opportunities there are and give States the opportunity to make this choice themselves.

MR. BOUCHER. Well, I am not sure there is a whole lot we could do, beyond just having this hearing, to inform States of what Virginia has done. I was thinking more about some kind of statutory provision that might focus attention a little more directly on it.

Let me just suggest this. If you have something in mind, or if you have a suggestion for us over the next month or two, why don't you share that with us, and we will take a look at what you present?

Let me turn to some other questions. I am concerned about what happened in Alaska. And briefly let me ask you about the crude oil spill that resulted in the loss of approximately 250,000 gallons of crude oil from a so-called low-stress transmission line in Alaska.

Your agency, I think, has the primary regulatory responsibility for these lines, does it not?

MS. GERARD. We have the statutory authority to exercise regulation. We had not exercised regulation at the time of this bill. That is a rulemaking that is underway. And yes, we should have primary jurisdiction over it.

MR. BOUCHER. Well, I mean, the statute is very clear. It says that you may not exempt regulation of a low-stress transmission line simply because it has no internal pressure.

MS. GERARD. Right.

MR. BOUCHER. So I think the intent of Congress was clear that you are supposed to regulate these lines. I take it from what you have just said that you have not done so so far, and rather than belabor why you haven't done so so far, let me look toward the future. You have got a regulation on the books, as I understand it, that basically says that there are three bases for exemption for such a line. One would be that it doesn't carry a high volatile liquid. I would assume that that is propane or butane. And these are independent bases for exemptions. The second would be that it is located in a rural area. And the third is that it is outside a navigable waterway.

Now it seems to me that these exemptions are so broad that one of them could probably be found for the vast majority of most pipelines in the country, not those in the city that cross a navigable waterway, maybe, but, you know, there is a very small window of opportunity for you to regulate these lines at all given the incredible breadth of this set of exemptions. I personally think these are exemptions that go well beyond the intent of our very clear statute. And they, I think, subvert the intent of the statute. And I would say to you that either you should change these or we need to, in the reauthorization of this Act, clearly direct you to regulate these lines in a way that is, perhaps, more precise than what we have done so far.

Any comment?

MS. GERARD. We completely agree that the regulations should be in place. We began it in 2004 and slowed down to finalize regulations where there was more evidence of human life at risk. But having completed those, we are rushing to finish this one. We put a notice in the Federal Register posting yesterday that laid out the areas that we intend to talk about publicly and give everybody else an opportunity to weigh in. It is the third week in June. We hope to have a consensus that day so that we can quickly finalize the regulation very shortly after that meeting. We wish we had the regulation in place today, and we completely agree that these lines should be regulated. We do regulate the low stress lines where people are and where there are navigable waterways, and this is the last piece of regulation to complete.

MR. BOUCHER. All right. Well, that is certainly a schedule that is a lot faster than the pace at which we will move, and so I wish you well with the exercise, and we will watch with interest the results of your rulemaking.

Mr. Chairman, with your indulgence, I just had one other question, but it is important, I think, that we ask this of the witness. Could I ask unanimous consent for another 90 seconds?

MR. HALL. Without objection, it is granted.

MR. BOUCHER. Thank you very much, Mr. Chairman.

We have heard from the Interstate Natural Gas Association an expression of concern about the timetables that are contained in the 2002 law for the initial baseline inspections, and that has to happen on a 10-year schedule, and then the periodic re-inspections following that baseline, which happen on a 7-year schedule. And as I understand the concerns the Association has expressed, they are worried that there will be some overlap between the 10-year baseline and the 7-year re-inspection and that this overlap might cause supply disruption for natural gas and that we might wind up in a situation where there are not enough inspectors, because they are doing, in essence, both inspections at once. And this is too much to expect for a limited supply of inspectors. So, you know, they are saying there may be disruptions. That may not be a perfect explanation of their concerns, but I think it is close.

I know the GAO is in the process of preparing a report. And I understand that leading up to that report there has been a suggestion to you that operators do not expect the overlap to cause problems and finding inspection contractors in order to conduct these reassessments. Is that an accurate statement of what you have heard so far? And if so, how do you square that with what we are hearing from the Interstate Natural Gas Association?

MS. SIGGERUD. Thank you.

It is a very important question, and it is right at the heart of what our work is looking at. Let me, first of all, tell you the timetable of our work. We will be looking at the 7-year reassessment interval from a couple of points of view. First of all, whether it is reasonable from a risk-based point of view, and I talked a little bit about that in my statement. We will also be looking at the ability of the regulated industry to comply and the possible impact on energy supplies. Our hope is to get a report to this and the other committees of jurisdiction in early October and to be able to brief your staff on our recommendations specifically on this issue a month or two before that, probably in late summer.

The Act does establish an overlap period. This happens between 2010 and 2012 when some of the assessments that occurred early in this time period will have reached their 7-year interval and will begin to need to be reassessed between 2010 to 2012. That is the same period under which these operators need to be finishing up the final 50 percent of baseline assessments that they are required to complete by 2012.

There are two major tools that we are hearing the operators are using to conduct their assessments and plan to use for their reassessments. One is in-line inspection. The majority are using this approach. The others are using direct assessment.

In our discussions with in-line assessment contractors and/or the operators themselves, they do anticipate having the ability to get access to those contractor resources. However, for direct assessment, this is a new technique that was established under the law, and there are a number of operators just coming into this field to try to perform this concept. Therefore, there is a low level of concern there.

We don’t have a complete answer on the energy issue at this time, but we do find operators are making plans and intend to deliver on the schedules that are required under the law. I also want to point out that there is a waiver authority that is available during that time period that should an operator anticipate an important or a difficult effect on local gas supplies, it may request a waiver from PHMSA. Most of the operators we talked with were aware of that opportunity.

I would like to point out, however, that there are no rules or guidance out on this yet in terms of what process should be used or what the criteria might be for approving such a waiver, if necessary.

MR. BOUCHER. And I suppose the waiver applications would be directed to Ms. Gerard, is that correct?

MS. SIGGERUD. That is right.

MR. BOUCHER. All right. And you are aware that you have that authority, Ms. Gerard?

MS. GERARD. Yes, sir.

MR. BOUCHER. All right. Have we had any applications? I guess not yet.

MS. GERARD. Not yet, but we could prepare quickly to receive them.

MR. BOUCHER. Okay. Well, that is comforting to know.

Mr. Chairman, you have been very generous with permitting me this amount of time. Thank you.

MR. HALL. The Chair recognizes Mr. Murphy, in the ability of the Chairman, for as long as he takes, I suppose, but I hope he limits it to 5 minutes.

MR. MURPHY. Thank you. I would ask unanimous consent to change it.

MR. HALL. Give yourself unanimous consent.

MR. MURPHY. [Presiding] Thank you, Mr. Chairman.

I just have 2 hours worth of questions for you all, and unanimous consent to agree to that. Thank you.

Yes, I would like to start off with a question for the panel, and this is probably more to Mr. Chipkevich. To begin with, can you tell the subcommittee more about the current investigations with regard to Pennsylvania, Kansas, and New Jersey recommendations that have come through to prevent future accidents, such as those that have occurred in those States?

MR. CHIPKEVICH. Sir, those are ongoing investigations at this point. But I can factually let you know that the staff has completed the investigation work for the DuBois, Pennsylvania accident and has forwarded that report to the Board for its consideration, who will review the entire report and any recommendations. That particular accident involved a gas distribution system with plastic mains and plastic service lines. There was a home that did explode following a gas leak, and there were fatalities involved in that. During the investigation, we did find a failure at a butt fusion joint in the main, so we had it examined extensively, in our laboratory, the mechanism of the failure and looking at the procedures that were followed, the procedures that are available nationwide.

MR. MURPHY. You recall the picture I put there. I am going to put that again, because one of the things that I understand is being pushed is a mixture of 811 systems being followed. And I understand as this bill is being drafted, the Department is working closely to make sure that prevention procedures are followed.

Well, let me run through the details.

What happened is a subcontractor was there and apparently ruptured a line that was clearly marked with blue paint. They had notified authorities before. And I think the breach occurred at 11:30 in the morning, and the gas company was finally notified at 2 o'clock in the afternoon and then arrived when the children came home from school. They were allowed to go into the house. No one stopped them.

In a situation like this, I am wondering, if the emphasis is going to be on notification using 811 or some other procedure, how do we prevent instances such as this once there is a breach that has occurred?

MR. CHIPKEVICH. The NTSB investigated an accident, and I believe it was about 1998 in St. Cloud, Minnesota. There was excavation damage to a distribution system and recognized as a leak that was ongoing, and what we found was that there was a delay in notifying local authorities and the local emergency response personnel. And in fact, rather, the excavator went through a process of notifying his home office first and then went through a process before local authorities were notified.

MR. MURPHY. What State was that in?

MR. CHIPKEVICH. That was in Minnesota.

As a result, another person then later notified the local fire department about the event, and they arrived on the scene, and there was an explosion before there were any evacuations that resulted in fatalities. As a result of that accident, NTSB had recommended that whenever there is a gas leak or somebody strikes a pipeline where there is a leak, whether it is a gas leak or a hazardous liquid leak, that a call be made to 911 so that local authorities get immediate notification, and made this recommendation both to PHMSA, the Pipeline and Hazardous Material Safety Administration, as well as to OSHA, because the Pipeline Safety Administration does not have authority over contractors, but we went also to OSHA to recommend in their standards that if a contractor does work and hits a pipeline to call 911.

This information went through a process through the Common Ground Alliance and has been incorporated as a best practice by the pipeline operators in their best practices for the Common Ground Alliance. However, there is still the issue of all of the contractors having the information out there. We have had positive feedback from OSHA, the Department of Labor, on this particular recommendation.

MR. MURPHY. Can I ask, then, you describe that what happened in Minnesota, in other words, is that they notified their home office and went through their procedures. Has Minnesota changed its laws to require 911 notification?

MR. CHIPKEVICH. To the best that I recall, I think they did after that accident.

MR. MURPHY. How about other States? Do we know if there is uniformity between States in terms of notifying 911 when there is a leak?

MR. CHIPKEVICH. I do not believe so. The process that we went to was to try to go to PHMSA as well as the industry on a national basis, but I do not think it is consistent across the country, the individual States.

MR. MURPHY. Okay. And I know in Pennsylvania and some other States, it is they have other notifications and not necessarily notifying 911. It may be notifying the local municipality. And in the case of this community, in their township, it was one that they would notify an office, which, essentially, was unmanned, because the maintenance people for the community are out during the day, so they didn't get a fax until someone came back in. Is that an adequate law just to notify if there is no one in the office?

MR. CHIPKEVICH. We certainly have found, from our investigation, that it is important to have an immediate notification to the local emergency response authorities.

MR. MURPHY. Why is the Department resisting notification of 911 as a law?

MR. CHIPKEVICH. Are you talking about the Office of Pipeline Safety?

MR. MURPHY. Yes, the Office of Pipeline Safety, Department of Transportation. Why is there resistance to use 911, putting that into law?

MS. GERARD. We don't have resistance. We support it.

MR. MURPHY. Then why does the Gas Association resist that?

MS. GERARD. Well, you probably need to ask them, but we definitely think that there is opportunity for the Congress to take some action that could motivate States to adopt this, and there are a variety of ways of doing that, but we think we certainly can support what you are wanting to do.

MR. MURPHY. Well, and I understand sometimes there is variability, assuming a rural community and they have a different need than a city or urban area. One possibility might be that Congress might say that States shall have some uniform rule in place to notify emergency authorities, whatever that might be, and leave it to the State to determine that. Would that fit and so allow some flexibility for States to determine their own needs?

MS. GERARD. I think if you can put the responsibility on the State to choose and adopt something and have some variation on that thing that it would work very well.

MR. MURPHY. Would you be willing to help the committee, obviously, go to the Chairman to help us understand some of the variability between State rules and laws? I would assume this gets in the way of a number of public safety issues, and it has got to be confusing for the gas companies that have the utilities, as they are drilling, if there are rules that change, not only between States, but between municipalities. It has to be very difficult for them, I would assume, and that would be helpful if you could assist us in understanding some of this variability between States and variability between municipalities.

MS. GERARD. We certainly will look forward to working with you on that.

MR. MURPHY. Thank you.

I see that the Chairman of the committee has arrived, and given that I believe my time has expired, I should defer to the Chairman.

Mr. Chairman, welcome.

CHAIRMAN BARTON. Thank you, Mr. Chairman.

It is good to be here. I have got another hearing going on and several other things, so I apologize for not being here for the entire hearing.

It is our intent, later this summer, to do basically a straight reauthorization of the existing Act. Do any of you folks have a problem with that? And if you do, you need to let us know what specific changes you would like to see us incorporate into the reauthorization.

Just go right down the line.

MS. GERARD. We think that there are opportunities to improve safety by putting additional focus on damage prevention, incentivizing States to adopt some of the practices that we have been discussing this morning. There has been testimony about some other opportunities that the Inspector General has mentioned today, and we will have, I believe, an Administration proposal to get up to you very soon with some other ideas.

CHAIRMAN BARTON. Excuse me, ma'am. Is this going to be a legislative proposal or just a statement of principles?

MS. GERARD. The Administration's legislative proposal we hope to have to you very soon.

CHAIRMAN BARTON. Great.

MR. ALVES. We support reauthorization and think that there are some things that could be strengthened. It is not entirely clear to us whether they need to be strengthened in reauthorization or whether they can be done administratively. In particular, we are concerned about making sure that there be a security annex to the Memorandum of Understanding between DOT and DHS over pipeline security issues. We think that can be done administratively.

The second issue that we have is a waiver authority in emergencies for the Secretary to be able to waive safety requirements. It was an issue in Katrina. He has the authority, excuse me, but only after public notice and an opportunity for a hearing. In an emergency situation like Katrina, that is probably not very useful, because actions need to be taken in a timely way.

Those are the two primary issues that we have at this point.

MR. CHIPKEVICH. Bob Chipkevich. We certainly believe that there has been significant improvement in pipeline safety since the 2002 Act and a lot of positive activity. We don't have any specific recommendations for legislation at this time, but we would certainly be glad to look into anything for you and provide any comments.

CHAIRMAN BARTON. Thank you.

MS. SIGGERUD. The GAO is required to do two studies and report out before the end of this year. We will be, in fact, reporting out this fall in both areas. The first asks us to look at the implementation of the integrity management program for natural gas transmission pipelines. We are generally going to give you a further review of the implementation and the safety effectiveness of that aspect of the Pipeline Act. We also are required to report specifically on the 7-year reassessment interval. We are going to be looking at it from several aspects, including the extent to which it is risk based and the extent to which it is having an effect on operators and the energy markets. We will have some recommendations for you in October in that area.

CHAIRMAN BARTON. Thank you.

This is a little off the point of the hearing, but we have got a lot of bright people here today, so I am going to ask you, Ms. Gerard.

In last year's energy bill, I led an effort unsuccessfully to do a limited safe water reliability for the Fuel Act of MTBE and set up a trust fund to clean up contaminated water supplies that had MTBE contamination. The Senate was not real receptive to the trust fund idea and the liability protection, so we dropped it from the bill. We didn't ban MTBE, but because of potential liability concerns, some of the major pipelines that were carrying gasoline that had MTBE in it, and these were privately owned pipelines, decided not to carry the MTBE gasoline. If you can't transport it, you can't distribute it, so consequently, even without a Federal ban on MTBE, there is basically no way to distribute it, so there is no market, so it is about to be gone. And in areas that were using it, like the area that I live in, the Dallas/Fort Worth area, we have had gasoline stations in the last month who didn't even have gasoline. And Texas, which is the largest producer of oil in the country, has got some of the highest gasoline prices in the country.

Is there any record that there has been a contamination problem caused by the transportation of MTBE and gasoline through the pipeline system?

MS. GERARD. I am not aware of any, sir. It is a little outside my area of expertise.

CHAIRMAN BARTON. Well, it is not the focus of the hearing, but, you know, gasoline prices are at all-time highs, and the Speaker and the President and their staffs almost every day are calling my office asking what I am going to do about it. And we will even be doing a number of hearings at the Full Committee level in the next month to do a comprehensive review of the energy sector. One of the things that I think might make some sense is to put some sort of a limited liability protection for the MTBE in place on a temporary basis so that those areas that were receiving MTBE gasoline could get the pipelines once again to carry it, and at least for the next year or two in those areas, you would probably see gasoline prices go down 20 or 30 cents a gallon because of that. So I just wanted to know on the record if you were aware of any contamination problems at the pipeline level caused by MTBE being added to the gasoline in the pipeline, and your answer is you are not aware?

MS. GERARD. I am not aware.

CHAIRMAN BARTON. Could you check officially with your agency and reply in writing on that question, please?

MS. GERARD. Yes, sir, I will.

CHAIRMAN BARTON. Thank you.

Thank you, Mr. Chairman.

MR. MURPHY. Thank you, Mr. Chairman.

The gentleman from Massachusetts arrived. Mr. Markey, you have 5 minutes.

MR. MARKEY. Thank you, Mr. Chairman, very much.

Mrs. Gerard, on March 2, 2006, BP officials discovered a leak in one of the transmission lines, which resulted in nearly 300,000 gallons of crude oil spilling into the sensitive arctic environment. Prior to the spill, had these arctic pipelines been subject to oversight and regulation by your Department?

MS. GERARD. No, sir.

MR. MARKEY. Now I understand that following the BP spill, your office issued a March 15 corrective action order to BP. Don’t you think it would be better if you could regulate these pipelines before an accident occurs rather than only having the power to come in after there has been a spill?

MS. GERARD. Well, that is a very important item. We began the rulemaking on this particular initiative about 2 years ago, but put it aside for some higher priority life safety initiatives. Now that they are completed, it is our top regulatory priority, and we have scheduled a public meeting in June, in which we hope to have a consensus to report.

MR. MARKEY. Is it your view that you should be able to get in before, not after?

MS. GERARD. Of course we would prefer to have prevented it.

MR. MARKEY. Okay. Now I am told that the trans-Alaska pipeline system that DOT does have ongoing regulatory authority over is scraped, using a device known as a “scraper pig” every 14 days in order to keep them clean of the sludge that might block the line or contribute to corrosion. In contrast, I have been told that the BP feeder line that leaked in March had not been scraped in 8 years. So Ms. Gerard, doesn’t that suggest the pipelines subject to ongoing oversight by your office are better maintained than those that are not?

MS. GERARD. That certainly seems to be the case here.

MR. MARKEY. Ms. Gerard, today’s Financial Times reports that BP will be unable to comply with the corrective action order issued by your office because the pipelines that have been up on the North Slope have been so poorly maintained. Is this true? And if so, how much of an extension have they asked for? And why do they need it?

MS. GERARD. At the time that we wrote the order, we did not realize that there was a large amount of deposits that had been built up inside the walls of these pipelines, which needs to be removed prior to the testing with a “smart pig.” We have been alerted by Alyeska Pipeline to the risk that moving a large amount of these deposits through their lines could cause, and so we are working with both companies to get a good picture on the amount, composition, and density of this material so that we can know how much there is and how long it is going to take to gradually remove it.

MR. MARKEY. Have they made a request for a specific time extension?

MS. GERARD. They have made more than one request.

MR. MARKEY. What is that? The most recent time extension request.

MS. GERARD. I believe the most recent request is for about a 4-to-6-week extension to be able to complete their diagnostics on this sludge material.

MR. MARKEY. Now it has also been reported that BP believes that there could be up to 2,500 cubic yards of oil sludge in key pipelines and that sending a scraper pig through those lines could, therefore, shut them down. Is that true?

MS. GERARD. It is possible that they could need to be shut down.

MR. MARKEY. If the BP lines up in Prudoe Bay were to be shut down due to the sludge, how many barrels per day of oil would be removed from the world’s oil markets?

MS. GERARD. I would have to get back to you on the record for that number.

MR. MARKEY. Ms. Gerard, how do you think BP could have allowed their pipelines up on the North Slope to deteriorate to this point?

MS. GERARD. Well, BP has employed a great number of different corrosion prevention methodologies. They apparently did not use this basic technique of running scraper pigs to remove the sludge, which is a hazard to the pipeline and--

MR. MARKEY. So what you are saying is it is just basic incompetence on their part?

MS. GERARD. We don't have any--

MR. MARKEY. Not using state-of-the-art technology?

MS. GERARD. We have no single logical reason why they did not use the scraper pigs.

MR. MARKEY. So how much would you attribute to incompetence on the part of BP, and how much of it to the fact that there was no regulatory oversight by the Federal government? How would you divide that responsibility?

MS. GERARD. It was our expectation that they would have been running those scraper pigs and that most companies do run the scraper pigs on a weekly to biweekly basis. There is a general standard of care that most operators exercise that are exercised without our regulating them. Obviously, we wish we had regulations in place sooner.

MR. MARKEY. Okay. It can't be, bogusly, that BP doesn't have enough money. Or is it just another cost-saving measure, regardless of what the consequences are?

MS. GERARD. I can't speak to how much money BP has, but it certainly seems like they should have been running scraper pigs on a weekly basis so that this problem didn't build up and occur.

MR. MARKEY. And what is their explanation to you for their failure to run the pigs? Is it the same one I gave to my mother for not cleaning my room? I mean, what is the answer?

MS. GERARD. I think there is a question about how much of the deposits there are and questions about how to remove them. We don't have a good explanation as to why they didn't start sooner, but obviously having not started sooner, the problem is more difficult today and is going to be hard to address, but we--

MR. MARKEY. But what is their explanation for not doing their job?

MS. GERARD. We don't have an explanation for why they did not run scraper pigs.

MR. MARKEY. No acceptable answer to you or no answer at all from them?

MS. GERARD. No acceptable answer.

MR. MARKEY. No acceptable answer.

Thank you.

Thank you, Mr. Chairman.

MR. MURPHY. Thank you.

Mrs. Wilson is here from New Mexico, yes. You are recognized for 5 minutes.

MRS. WILSON. Thank you, Mr. Chairman. I appreciate your patience.

I wanted to ask, and none of you touched on this in your testimony, although you do talk about significant progress being made in examining pipelines and so forth, what research and development is underway to better identify and prevent pipeline problems and take technologies to the next step, either sponsored by the Federal government or on their way in industry?

MS. GERARD. Since the Pipeline Safety Improvement Act of 2002, we began a research program, really, for the first time that focuses on a range of integrity issues, from prevention to detection to repair techniques and so on. We have funded about 30 projects to look at bringing short-term technologies to market, and there are 8 patents pending from this work. We are very optimistic about the ability to use technology to be able to direct sooner and to be able to do detection in areas where pipelines, for example, cannot be inspected with a pig type device, for example.

MRS. WILSON. Thirty projects, eight patents pending, what is the total amount of money that you all have put into R&D from the Federal budget?

MS. GERARD. It is now 38 projects, and it is about $30 million maybe on the Federal side with more than that matched on the private-sector side, so about a $50 to $60 million investment.

MRS. WILSON. What do we spend using old technology annually in private industry to inspect these pipelines? How expensive is it to do this job?

MS. GERARD. This is just a rough guess, but I would expect that an average pipeline company will spend at least $100 million using detection prevention technologies.

MRS. WILSON. Anybody else have a better answer?

Well, it continues to concern me that when we look at remote detection technologies and sensing technologies in other industry areas, we are making such tremendous advances, whether you look at telecommunications. France has spent a lot of working time in intelligence. And pipeline safety R&D for remote detection and sensing is moving so slowly, and it is stuck somewhere in the 20th Century, and I just don’t understand why we are not leveraging other investments.

MS. GERARD. We have a number of investments dealing with use of remote sensing technologies and would be happy to provide you with a description for the record.

MRS. WILSON. I would very much appreciate that information. And Mr. Chairman, I think this is an area where there is substantial work to be done and substantial other Federal investment that can be leveraged in this area that will reduce operating costs for those who operate pipelines and improve safety.

Thank you, Mr. Chairman.

MR. HALL. Thank you.

I think that concludes your presentation. We thank you very much for it.

We will now prepare for the second panel.

We appreciate the time that you took to prepare research, to travel here, and to give us your expertise. It is people like you that help write the laws that we all live under, and I thank you for your appearance here.

MR. ALVES. Thank you, Mr. Chairman.

MR. HALL. We have the Honorable Donald Mason, the Commissioner of Public Utilities Commission of Ohio. He is running a little bit late, but he will be here in a little bit. And Mr. Massoud Tahamtani, did I say it right?

MR. TAHAMTANI. Yes, sir.

MR. HALL. Pretty close?

MR. TAHAMTANI. Yes, sir.

MR. HALL. The Director, Division of Utility and Railroad Safety, Virginia State Corporation Commission, and we will recognize you first, since you are the only one here. I ask you to use about 5 minutes, if you can. If you have to go over a little, we understand that. We recognize you at this time. Thank you.

STATEMENTS OF MASSOUD TAHAMTANI, DIRECTOR, DIVISION OF UTILITY AND RAILROAD SAFETY, VIRGINIA STATE CORPORATION COMMISSION, ON BEHALF OF NATIONAL ASSOCIATION OF PIPELINE SAFETY REPRESENTATIVES; AND HON. DONALD L. MASON, COMMISSIONER, PUBLIC UTILITIES COMMISSION OF OHIO, ON BEHALF OF NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

MR. TAHAMTANI. Thank you, Mr. Chairman, Congressman Boucher, members of the subcommittee.

Good morning. My name is Massoud Tahamtani, and I am the Director of the Division of Utility and Railroad Safety for the State Corporation Commission of Virginia. Our division assists our commissioners in administrating safety programs involving pipeline facilities, railroads, and underground utility damage prevention.

Thank you for inviting me to participate in this important hearing.

I have been asked to comment on Virginia's underground utility damage prevention program as it relates to pipeline facilities. The specifics of this program are detailed in my written testimony, which was submitted earlier.

I could talk about this for hours, but I will talk for about a few minutes.

Mr. Chairman, this program is about 15 years old, and I have been talking about it for the last 10 years, at least. But I will leave my comments to a brief summary of how the program started and what makes it work.

The Virginia damage prevention efforts began in 1992, not because of an accident, but because we noticed excavation damage to our pipelines was increasing at an alarming rate. In order to address this serious threat, our commission appointed tasks for the key stakeholders to conduct a comprehensive review of our damage prevention law and make recommendations that would help significantly reduce excavation damage to all underground facilities.

To ensure the success of this task force, the commission created an environment where, for the first time, all stakeholders were put on equal footing. As I am sure you know, contractors always think that they are the small guys and utilities are the big boys and they never have a voice in the process. We corrected that, beginning in 1992, and continue to practice that today.

The task force's recommendations, with minor changes, became the Virginia law that Congressman Boucher noted. The new law contained a number of key provisions, which can be grouped into three categories: improved communication, effective enforcement, and effective public education.

With the new law on January 1, 1995, we began our enforcement program with voluntary reporting of gas damages by gas companies. By the end of 1995, only 30 out of 2,500 damages had been reported to us for investigation. That is only 1.2 percent. Obviously, an effective and meaningful enforcement program could not be carried out by taking action on a select few damages. As a result, beginning with the 1996 calendar year, we required all gas operators to report all damages and violations of our law for investigation and possible enforcement actions.

Along with our enforcement, we strongly encouraged the broad participation of all stakeholders to help improve Virginia's damage prevention program. In 1999, soon after the U.S. DOT's study of damage prevention best practices was released, we compared our law, rules, and practices to the best practice contained in that study. With full participation of key stakeholders, we began a rulemaking and, in 2001, adopted commission rules to improve the program even further. Twenty issues that were best practices were not really addressed by our law or rules. The commission again invited stakeholders to serve on a task force to study these issues and recommend a resolution. The recommendations made by this task force again were adopted into our law.

The commission rules and the 2002 amendments to the law addressed additional but very important damage prevention requirements for excavators, operators, locators, and the notification center. In order to effectively communicate all safety and these additional requirements, the commission formed another committee of stakeholders to guide Virginia's public education program. Every year, this committee recommends and the commission adapts the statewide education and public outreach program. Our law requires that all the penalties collected from these fines be spent on public education.

Now a few words about our results.

In 1996, when we began to report gas damages, Virginia's gas distribution system, since 1996, has grown by 30 percent. So 30 percent more facilities are protected. Sixty percent more excavation is happening at least around Virginia. With those two, we have reduced damages to gas pipelines by 50 percent. So as you can see, this is a very impressive result, and that is why you keep hearing the name of Virginia here.

Over the last 10 years, more gas facilities have been put in the ground and need protection from more excavation, and we have managed to reduce these damages to our pipelines. The success of our program clearly can be attributed to nine factors that you have seen and will hear about again: enhanced communication between operators and excavators; partnership in public education; partnership in training the contractors, locators, and on-call center employees; commission role as a partner and facilitator; efficient, fair, and consistent enforcement; user performance measures for persons performing locating and also constructing utility facilities, and these are the individuals who work around the existing facilities more often; using available technologies to improve the process; and then finally, continual review to help evaluate and improve the program.

As I indicated, the details behind each of these elements are in my written testimony, and I will not get into it here, but I will be happy to answer any questions.

Finally, Mr. Chairman, on behalf of the National Association of Pipeline Safety Representatives, these are my colleagues from other States, I want to encourage Congress to provide additional grants to States to assist them with their increased pipeline safety responsibilities, including having an effective damage prevention program. We specifically request that the 50-percent pipeline safety grants in the Act be raised to 80 percent. This is consistent with other DOT grants to States, and we have a $1 million damage prevention grant that I helped to hopefully give to the States. We need that to be increased to $2.5 million to better help the States carry out their current damage prevention programs.

Thank you, Mr. Chairman.

[The prepared statement of Massoud Tahamtani follows:]

PREPARED STATEMENT OF MASSOUD TAHAMTANI, DIRECTOR, DIVISION OF UTILITY AND RAILROAD SAFETY, VIRGINIA STATE CORPORATION COMMISSION, ON BEHALF OF NATIONAL ASSOCIATION OF PIPELINE SAFETY REPRESENTATIVES

Summary of Testimony

Virginia State Corporation Commission appreciates the opportunity to discuss our Underground Utility Damage Prevention Program. Over the last 10 years, we have managed to reduce excavation damage to our pipeline facilities by more than 50 percent. This is especially significant in light of the fact that our gas system has grown by more than 30 percent and the notices of excavation have increased by more than 60 percent over the same period. Our results are due to our comprehensive damage prevention program which includes the following elements:

- Enhanced communication between operators and excavators;
- Partnership in public education;
- Partnership in training of excavators, locators and one-call center employees;
- Commission's role as a partner and facilitator;
- Efficient, fair and consistent enforcement;
- Use of performance measures for persons performing locating of facilities and constructing new utility facilities;
- Use of available technology to improve the process; and
- Continual review of data to help evaluate and improve the program.

We encourage Congress to provide additional grants to states to assist them in better carrying out their increased pipeline safety responsibilities including the implementation of effective damage prevention programs. Specifically, we support increasing the current 50 percent pipeline safety grants to states to 80 percent and increasing the current $1 million damage prevention grant to $2.5 million to assist states with current damage prevention efforts.

Mr. Chairman and Members of the Subcommittee,

Good morning. My name is Massoud Tahamtani and I am the Director of the Division of Utility and Railroad Safety for the State Corporation Commission in the Commonwealth of Virginia. Our Division assists our Commissioners in administering safety programs involving pipeline facilities, railroads and underground utility damage prevention. Thank you for inviting me to participate in this important hearing.

This morning, I have been asked to focus on Virginia's underground utility damage prevention program as it relates to pipeline facilities. Over the next few minutes, I hope to share with you how our program has evolved to where it is today and the steps we are taking to ensure its continued effectiveness.

Background

As we all know, in the late 1980's and early 1990's, excavation damage to pipelines across our country increased at an alarming rate. Several of these damages resulted in serious accidents involving deaths, injuries and millions of dollars in damage to properties and the environment.

In order to address this serious threat to Virginia's pipeline system, in 1992 our Commission appointed a task force of stakeholders to conduct a comprehensive review of our damage prevention law and recommend changes that would help significantly reduce excavation damage to our underground facilities. This task force included representatives from operators, excavators, underground facility locators, local and state government as well as the notification centers.

To ensure the success of this task force, the Commission created an environment where, for the first time, all stakeholders were placed on an equal footing so that individual issues would not override our ultimate goal of significantly reducing damages to all underground facilities in Virginia.

In early 1993, the Virginia General Assembly recognized the work of the task force and requested the Commission to submit a report and any recommendations to the Assembly's 1994 Session. The task force's recommendations with minor changes were adopted into law effective January 1, 1995.

Virginia's New Damage Prevention Law

The new law contained a number of key provisions, which can be grouped into the following three categories: Improved communication, Effective enforcement and Effective public education.

Improved Communication

The stakeholders believed that first and foremost, the exchange of timely information between the excavators and operators needed to improve. This was accomplished by having the law require:

- The notification centers operating in Virginia to design and implement a "Positive Response System" to enable operators to efficiently communicate the marking status of their facilities to excavators;
- Excavators to provide an additional notice to the operator(s), through the notification center, when they observed clear evidence of unmarked facilities and wait an additional three hours for operators to mark their facilities;
- The notification centers to re-notify the operators who had failed to respond to the "Positive Response System" 48 hours after the notice of excavation.

These three requirements assisted the stakeholders in Virginia to eliminate the gaps that occurred in their communication and to strengthen the partnership which is critical to a successful damage prevention program.

Effective Enforcement

Just as our founding fathers believed that self government was more effective than any government from afar, the law created a way for the enforcement to come from the stakeholders themselves. Thus, included in our new law was a directive to the Commission to appoint a Damage Prevention Advisory Committee ("Committee") comprised of expert representatives from operators, excavators, facility locators, notification centers, local government, Virginia DOT, the Virginia Board for Contractors and the Commission Staff. This Committee was charged with assisting the Commission in furthering Virginia's damage prevention program by reviewing reports of damages and violations and by making enforcement recommendations to the Commission. It was believed that this administrative process would result in a fair and consistent enforcement program without costly legal proceedings.

Effective Public Education

Effective education and training is critical to changing behaviors and impacting results. To better accomplish this, the law required all penalties collected from the enforcement program be kept in a "Special Fund" account to be used for training, education and enforcement. In addition, the law required all operators to assist in the education of the public relative to safe digging practices.

With a new law, on January 1, 1995, we began our enforcement program with voluntary reporting of damages by gas operators. By the end of 1995, only 30 of more than 2,500 damages to pipelines, or 1.2 percent, were reported to the Commission for investigation. Obviously, an effective and meaningful enforcement program could not be carried out by taking actions on only the select few damages which were being reported. As a result, beginning with the 1996 calendar year, we required all our gas operators to report all damages and violations involving their facilities for investigation and possible enforcement actions.

Along with our enforcement program we strongly encouraged broad participation of all stakeholders to help improve Virginia's damage prevention program. The combination of these efforts resulted in a 26.5 percent reduction in gas pipeline damages by 1998. Meanwhile, several serious pipeline accidents across the nation prompted Congress to take action.

As you know, in 1998, the Transportation Equity Act for the 21st Century (TEA21) was signed into law. Section 6105 of this Act authorized the USDOT to undertake a study to determine which existing practices were most effective in reducing excavation damage to pipelines and other underground facilities. Soon after USDOT's study was released in 1999, we compared our law, rules and practices to all the "Best Practices" contained in that study.

As a result, we began a rule making and in 2001, adopted specific rules to further improve Virginia's damage prevention program. Our comparison also identified 20 issues that could not be addressed through rule making. The Commission again invited stakeholders to serve on a task force to study these issues and recommend resolutions. The recommendations made by this task force resulted in further improvements to our law in 2002. The Commission's Rules and the 2002 amendments to the law addressed a number of very important damage prevention requirements that can be grouped as follows:

Excavators are required to:

- Take reasonable steps to avoid damage during routine and emergency excavations;
- Take nine specific steps when conducting trenchless excavation;
- Conduct pre-excavation site inspections and preserve markings during excavation; and
- Take reasonable care when hand-digging around utility facilities.

Operators are required to:

- Update the notification center's data base any time they place new facilities in operation;

- Maintain accurate records of their active facilities as well as facilities abandoned after July 1, 2002;
- Provide underground utility information to project designers;
- Make all new non-metallic underground lines locatable; and
- Place underground utility lines at specific depths.

Notification Centers are required to:

- Include non-operators on the center's board; and
- Meet certain performance standards.

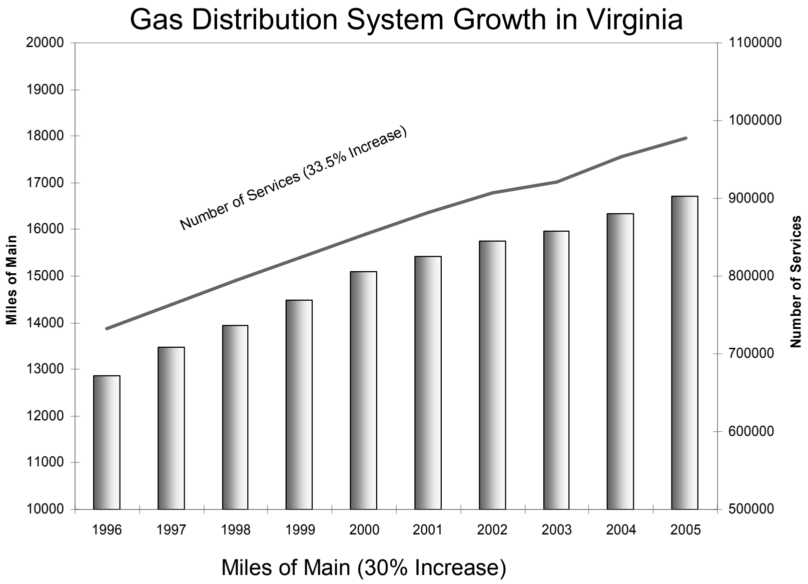
Locators are required to:

- Follow certain standards for marking underground utility lines; and
- Be trained based on their industry standards.

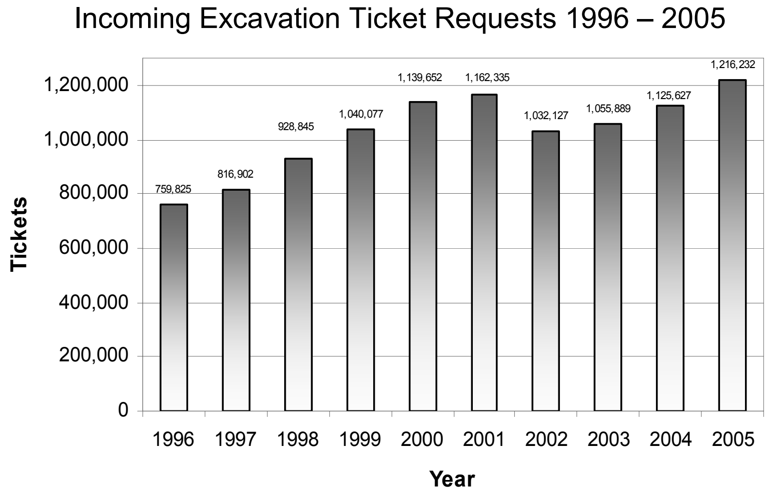
In order to effectively communicate these additional requirements to the stakeholders, the Commission formed a statewide education and training committee again comprised of representatives of key stakeholders. Every year, this committee recommends and the Commission adopts a statewide education and public outreach program. I will review the details of this program later in this testimony.

Results

Since 1996, when we began our mandatory reporting of all gas damages, Virginia's gas distribution system has grown by more than 30 percent.



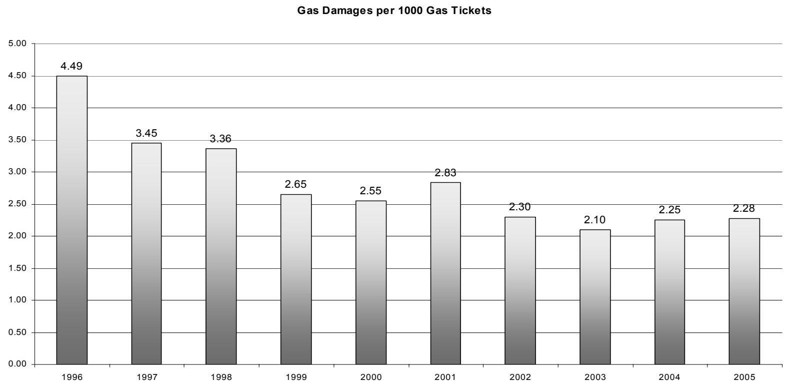
During this same period excavation notices also known as "tickets" has increased by more than 60 percent.



Incoming Ticket Volume (60.06% Increase)

Finally, the index that is often used to measure the success of a damage prevention program, damages/1,000 tickets, for our gas system, has decreased from 4.49 in 1996 to 2.28 in 2005. This is a 50 percent reduction in excavation damage to gas pipelines in Virginia.

Statewide Gas Facility Damage Trend



A review of the previous three charts shows that although over the last 10 years, more gas facilities were constructed and needed protection from increased excavation activities, Virginia has managed to realize a significant reduction in gas damages. The success of this program can clearly be attributed to our comprehensive damage prevention program which has been based on the following:

- **Enhanced communication between operators and excavators**. The exchange of accurate and timely information between the excavators and operators of underground facilities is at the heart of any effective damage prevention process. The easier and the more efficient this communication, the more effectively the two main stakeholders (excavators and operators) can communicate throughout the excavation activity. Virginia was the first state to implement the Positive Response System and require excavators to learn the status of their tickets by contacting this system before commencing excavation. Our "three hour notice" is another opportunity for excavators and operators to ensure they are "talking" when unmarked facilities are noted in the field. The requirement for the center to re-notify operators when they have failed to respond to the system is yet another way to ensure additional communication when a request for marking seems to have not been acted upon. Finally, the requirement for locators to add company specific letter designations and facility information when they mark the facilities is another way to better provide the excavators with information relative to a facility they need to protect from damage.
- **Partnership in public education.** As noted earlier, a committee of stakeholders currently guide Virginia's public outreach program. Annually, this committee reviews a significant amount of data to determine the effectiveness of our education and outreach program and recommends to the Commission the specific elements of a new program for the upcoming year. Through this process, outreach campaigns of at least one million dollars per year have been implemented since 2001. To assist in training of stakeholders, the Commission has three full time trainers on staff who conduct face to face training for more than 3,500 individuals every year. Our utilities provide significant assistance in increasing the overall value of our educational campaign. For example, this year's campaign is valued at more than $3.2 million with approximately $1.2 million dollars of free PSA's being provided by our cable and telecommunications companies. The gas operators have completed several unique initiatives such as having our safe digging message on a 2.5 million gallon LNG tank, on a building front, on gas meters, on gas pipeline markers, on company vehicles and bills, just to name a few. The annual campaign and the efforts of our partners keep our safe digging message in front of the public eye at all times.
- **Partnership in training of excavators, locators and one-call center employees.** Effective training of those individuals involved in excavation, locating and marking of facilities and the notification center operation is also critical in reducing damage to underground facilities. In Virginia, most of our training is done by teams representing the stakeholders. Additionally, we have developed a "Train the Trainer" program to certify individuals to conduct training for their own employees or assist in training others. We also have an education credit program that encourages companies and individuals to get involved with educating their own employees or other companies' employees and receive credit to reduce possible future penalties.
- **Commission's role as a partner and facilitator.** As a result of our active damage prevention program, we have been presented with many different issues, the proper resolutions of which have been critical to the overall success of the program. When issues have required the involvement of all stakeholders, we have formed task forces, committees, etc. to quickly address these issues. Our Damage Prevention Advisory Committee, which meets monthly, has become the first place where issues or concerns are discussed. These discussions have resulted in recommending revisions to the law, rules,

procedures and policies. In all of these processes we have worked hard to ensure fairness to all stakeholders.

- **Efficient, fair and consistent enforcement.** As noted earlier, the results of investigations of damages and violations are reviewed by an Advisory Committee appointed by the Commission. The make up of this Committee is as follows:

Representing	No. of Members
Excavators	3
Operators	2
Utility Locators	2
Notification Center	1
Local Government	2
VA DOT	1
Virginia Board for Contractors	1
Commission Staff	1

After a review of the facts surrounding each incident, the Committee makes enforcement recommendations which may include: civil penalty, civil penalty with training, warning letter, letter of concern, or dismissal. Every recommendation is made by considering factors such as circumstances that led to the incident, culpability, gravity, history of the violator and other factors that may be justified. When civil penalties are necessary, a fairly complicated set of matrices guide the investigators and the Committee in recommending the appropriate level of civil penalties for settlement purposes while maintaining consistency. If applicable, a performance improvement credit is applied to reduce the penalty and therefore recognize a stakeholder's overall performance. There are several opportunities for the involved parties to present their information and positions to the Committee outside a formal hearing. The Committee operates based on approved bylaws and strict policies to ensure the consistency and credibility of its process.

- **Use of performance measures for persons performing locating of facilities and constructing new utility facilities.** Quality assurance programs must be in place to monitor and ensure that locators perform their duties properly when they locate facilities. Also, contractors working for utilities must be monitored to ensure their full compliance as they mostly work around existing facilities. In Virginia, we have encouraged our operators to have incentives (penalties) tied to the performance of locators and utility contractors to further improve the operators' damage prevention programs.
- **Use of available technology to improve the process.** When a recent analysis of our data showed that damages caused by hand digging were on the rise, we encouraged our excavators to take advantage of air-knife technology and trenchless excavation using water to reduce these damages. When an operator had more than 30,000 unlocatable gas service lines, we encouraged that operator to use existing technologies to make their facilities locatable. Finally, our notification center has employed a number of technologies to improve its performance in providing timely service to excavators and operators. In three months, the center will implement new mapping technologies to better serve its customers.
- **Continual review of data to help evaluate and improve the program.** Over the last 10 years, we have investigated more than 25,000 damages to our gas facilities. The cause of every single damage has been identified by our Committee of experts. For every incident, important information is gathered and maintained in a single database at the Commission. In addition, the

> notification center is required to capture and maintain data relative to every notice of excavation and every utility response to these notifications. The combination of these two data bases has allowed Virginia stakeholders to review the trends and to take appropriate and focused actions to improve the program. For example, data is used to effectively plan and implement the statewide education outreach program. Data is also used to share trends with our gas operators and devise plans to address problem areas.

Virginia Damage Prevention Pilot Project

Due to Virginia's mature and successful program, our state has been selected as a pilot state by a number of organizations, including the Common Ground Alliance ("CGA"), the Pipeline Research Council International, Inc. ("PRCI"), the Office of Pipeline Safety, and the various operators having facilities in Virginia. The purpose of this pilot project is to research and implement new and existing technologies such as GPS technology to further improve the communication of accurate information among excavators, one-call centers and operators. The results of this pilot will benefit every states' damage prevention program.

Distribution Integrity Management

As you know, a recent study on integrity management for gas distribution systems was completed in December, 2005. This study was conducted by four joint government/industry groups. The Excavation Damage Prevention Group ("EDPG"), which I chaired, found excavation damage by far poses the single greatest threat to distribution system integrity. EDPG further found that comprehensive damage prevention programs were needed to significantly reduce accidents caused by excavation damage to pipelines. Further, the group found that federal legislation is needed to support the development and implementation of damage prevention programs that include effective enforcement as part of a state's pipeline safety program. States should be encouraged to incorporate pipeline damage prevention responsibilities with their pipeline safety programs. The costs associated with carrying out effective damage prevention programs along with resources needed to fund the current pipeline safety program, as well as implementing the recent safety mandates justifies increasing the 50 percent grant ceiling contained in the law to 80 percent. This funding level is consistent with other non-pipeline safety grants to states administered by USDOT. Any effort to significantly reduce excavation damage threats, which are the most preventable of all, is very much consistent with Congress's overall pipeline safety objectives. For any federal legislation to be effective, it must include provisions for additional grants to support the states' damage prevention and pipeline safety programs. We also support increasing the current $1 million Damage Prevention Grant to $2.5 million dollars to assist all states with their existing damage prevention efforts. As I serve on the federal/state committee that helps to review the applications for the $1 million, I know that a number of states' entire damage prevention program depend on this grant which has been very effective in supporting limited yet effective activities by these states.

Mr. Chairman, this concludes my testimony. Once again, thank you for the opportunity to participate in today's hearing.

MR. HALL. I thank you.

And we note the presence of Mr. Mason. Welcome. I understand traffic problems and time pressures. And thank you for being here.

We will recognize you at this time to receive your testimony for about 5 minutes or more to accommodate your full presentation to us, and then we will have questions for both of you.

Thank you, and we recognize you, Mr. Mason.

MR. MASON. Good afternoon and thank you, Mr. Chairman. I guess we are still in the morning. Good morning, Mr. Chairman and members of the subcommittee.

As indicated earlier, my name is Don Mason, Commissioner of the Public Utility Commission of Ohio. I also serve as Chairman of the Gas Committee of the National Association of Regulatory Utility Commissioners. I am speaking on behalf of NARUC and the PUCO with regard to my prepared testimony.

As indicated earlier, NARUC members actually regulate the retail rates and services of gas, electricity, and water. My testimony represents that of the technical individuals as well as the policy individuals who determine how to allocate the rates across the States.

My first point gets into grant funding. We feel it must increase to meet our resource requirements of the State pipeline safety programs. Consumers ultimately pay the Pipeline Hazardous Materials Safety Administration pipeline users' fees that are passed on by natural gas and hazardous liquid transmission companies. Again, all of the rates and fees get passed on to the consumers in the end. State pipeline safety program funding is heavily dependent on PHMSA's proper sharing of these user fees and the State pipeline safety programs represent approximately 80 percent of the Federal/State workforce that oversees the pipeline nationwide. So without the adequate funding, States would not be able to conduct the required inspections of the existing pipelines.

The Pipeline Safety Act provides for States to receive a Federal grant up to 50 percent of the actual expenses for their safety programs, and in 2005, the State estimated cost of the portion was actually around $36 million, but due to the 50-percent funding, we did not receive the entire funding. It looked like the Federal government funded about $15.9 million. So roughly, there is a disproportionate sharing where the States are bearing a little more of the load, and I might point out that States are responsible for about 2.14 million miles of the total 2.41 million miles of pipeline. So in other words, we are responsible, really, for about 89 percent of the pipelines in the United States of America. So our burden is fairly heavy, and we hope that Congress will recognize the need for additional support of the State inspection resources.

And may I also say that Congress, we feel, should increase the current $1 million damage prevention grant to about $2.5 million. For several years now, Congress has funded a $1 million grant to assist all States with their existing excavation damage prevention programs. PHMSA receives about $2.2 million in requests, so as you can see, our requests exceed the budgeted amount. And many States that cope with the enforcement would be restricted without the funding that is set aside in this grant, as it is now. Much of the data collected to evaluate damage prevention program effectiveness and its needs is made possible by one-call grants. Incentives such as equipment and training supported by grant funding have been effective in bringing small operators of limited financial means into compliance with our State damage prevention laws.

On the good news side, in March of 2005, your States, basically through the help of the FCC, of course, the Pipeline Safety Act of 2002 authorized the one call, which starting about a year ago, we have all been working on a one-call system. That is the 811. We hope it will really reduce the amount of damage to pipelines and other facilities. I can't emphasize enough how we need to continue to promote the public awareness of 811 so that more people will call before they dig, because again, third-party cut-ins still represent over 50 percent of the damage to pipelines.

And I will just summarize in closing, and then I will bounce to a couple of points that we have been working on.

We have been working really hard with PHMSA, not just the States in the program, a lot of shareholders, in trying to allocate just the right amount of flexibility and the right amount of responsibility on inspecting the distribution and integrity management system. Right now, we have sort of a Federal flexibility plan in place that we support. But part of that also includes looking at something called excess flow valves that became an issue at one point where there was concerned that EFVs, as they are called, would be mandated across 100 percent of the country. We have concern that you have to have the right pressure to make these systems operate, the right constituents in the gas to make sure they operate. For example, in parts of Ohio, and other production areas, I am sure in Texas, there are gas constituents that could actually gum up the works, distribution systems operating too close to a production area, as so many do.

With that, I will just close my remarks, and I am ready to help answer questions with my partner here.

Thank you, Mr. Chairman.

[The prepared statement of Donald L. Mason follows:]

PREPARED STATEMENT OF THE HON. DONALD L. MASON, COMMISSIONER, PUBLIC UTILITIES COMMISSION OF OHIO, ON BEHALF OF NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

- Grant funding must increase to meet resource requirements of State pipeline safety programs.
- Congress should increase the current $1 million damage prevention grant to States to $2.5 million.
- Distribution Integrity Management programs should provide additional safety improvement.

- NARUC supports 80% grant funding for all pipeline safety programs that enforce excavation damage prevention distribution integrity inspections and other mandated programs.
- Federally mandated installation of excess flow valves (EFVs) on service lines to customers is not necessary.

Good Afternoon Mr. Chairman and Members of the Subcommittee.

I am Donald L. Mason, a commissioner at the Public Utilities Commission of Ohio (PUCO). I have served in that capacity since 1998. I also serve as the Chair of the Committee on Gas for the National Association of Regulatory Utility Commissioners (NARUC). As Chairman of the NARUC Committee that focuses on some of the issues that are the subject of today's hearing, I am testifying today on behalf of that organization. In addition, my testimony reflects my own views and those of the PUCO as well as the comments of the National Association of Pipeline Safety Representatives (NAPSR) reflected in items 1, 2, 3 & 5. On behalf of NARUC, NAPSR and the PUCO, I very much appreciate the opportunity to appear before you this morning.

NARUC is a quasi-governmental, non-profit organization founded in 1889. Its membership includes the State public utility commissions serving all States and territories. NARUC's mission is to serve the public interest by improving the quality and effectiveness of public utility regulation. NARUC's members regulate the retail rates and services of electric, gas, water, and telephone utilities. We are obligated under the laws of our respective States to ensure the establishment and maintenance of such utility services as may be required by the public convenience and necessity and to ensure that such services are provided under rates and subject to terms and conditions of service that are just, reasonable, and non-discriminatory. NAPSR is a non-profit organization of state pipeline safety directors, mangers, inspectors and technical personnel who serve to support, encourage, develop and enhance pipeline safety.

This morning I will focus on what NARUC believes are the five main issues facing the States with regard to the pipeline safety program.

1. Grant Funding Must Increase To Meet Resource Requirements Of State Pipeline Safety Programs.

State pipeline safety agencies are closely connected to the ultimate consumers of natural gas and liquid hydrocarbons through the oversight of facilities that distribute products near or at the end of the transportation supply chain. These consumers ultimately pay the Pipeline Hazardous Material Safety Administration (PHMSA) pipeline safety user fees that are passed on by natural gas and hazardous liquid transmission companies. State pipeline safety program funding is heavily dependent upon PHMSA's proper sharing of these user fees. State pipeline safety programs represent approximately 80 percent of the federal/State inspector work force that oversees pipelines nationwide. Without adequate funding, States will not be able to conduct the required inspections of the existing pipeline facilities or new pipeline construction projects, and encourage compliance with new and existing safety regulations. Grant funds are an effective way to leverage resources and increase total inspection capability since States match or exceed federal funding provided for pipeline safety.

However, federal base grants to States who administer the gas and liquid pipeline safety program are not keeping up with their actual expenditures. The Pipeline Safety Act provides for States to receive a federal grant up to 50 percent of actual expenses for their safety programs. For example, in 2005 the States estimated that the total cost of their portion of the program to be approximately $36.2 million. Due to the 50 percent limit imposed in the Pipeline Safety Act, the most the States can be granted to cover their costs was $18.1 million. However, the actual base funding grant level that was given to the States was $15.9 million.

State pipeline safety programs have jurisdiction over 222,000 miles of natural gas & liquid transmission and gathering lines, 1.15 million miles of natural gas distribution pipelines and 764,000 miles of service lines. Therefore, States are responsible for over 2.14 million of the total 2.41 million miles of pipe (PHMSA oversees 272,000 miles), which represents 89 percent of the total pipelines in the United States. However, while the States are responsible for 89 percent of the pipelines, in FY 2005 they only received 28% of the total dollars appropriated by Congress for pipeline safety. Unless Congress recognizes the need for additional State inspection resources this funding shortfall will continue to widen in the future, jeopardizing the States' working relationship and partnership agreement with PHMSA creating a potential public safety concern.

The responsibility for State pipeline safety programs is carried out by approximately 325 qualified engineers and inspectors who represent more than 80 percent of the State/federal inspection workforce that are currently inspecting natural gas and liquid pipeline operators on a daily basis.

State inspectors are the "first line of defense" at the community level to promote pipeline safety, underground utility damage prevention, public education and awareness regarding pipelines, interface with emergency management agencies on security and reliable energy issues. Daily activities include inspection of existing facilities, renewal or new pipeline construction projects, review of safety maintenance and operations records, drug and alcohol records, compliance and enforcement actions, training and education programs for operator and public, and accident investigation of reportable incidents.

State inspectors are required to attend nine mandatory training and computer based training (CBT) courses provided by PHMSA's Transportation Safety Institute within three years of employment with a State agency and refresher training required within 7 years of their attendance to the course. These one week courses already impact State expenditures and resources for the program, however, PHMSA has recently added two additional courses that gas safety engineers must attend in order to act as their agent and participate in integrity management audits. We believe all the courses are positive. It seems, however, the federal government is providing additional mandates while not funding the program at a level commensurate with the existing responsibilities, let alone any additional requirements.

2. Congress Should Increase The Current $1 Million Damage Prevention Grant To States To $2.5 Million.

For several years now, Congress has funded a $1 million grant to assist all States with their existing excavation damage prevention programs. Every year, PHMSA receives more than $2.2 million in requests from States to support and continue their existing prevention efforts. NARUC is respectfully requesting that Congress increase this very important grant to at least $2.5 million to better support existing damage prevention efforts.

One-Call grants have enhanced state damage prevention efforts by funding a wide range of enforcement, incentive, and awareness activities. In many states the scope of enforcement would be restricted without this funding. Much of the data collection to evaluate damage prevention program effectiveness and needs is made possible by the One-Call grants. Incentives such as equipment and training, supported by grant funding, have been effective in bringing small operators of limited financial means into compliance with state damage prevention laws. Grant-assisted training for excavators has improved their knowledge of State One-Call laws and safe excavation practices, but must be on-going to remain effective. The One-Call grants support changes in State damage prevention law to meet federal guidelines. And the grants have greatly assisted State actions to educate local officials, excavators, utilities and the public on One-Call awareness and the importance of preventing damage to all underground facilities.

In March 2005, with NARUC's strong support, the Federal Communications Commission designated the 811 number as the national abbreviated dialing code for One-Call systems to comply with the Pipeline Safety Act of 2002. The three-digit number 811 will be easy to remember and use by excavators to help reduce damages to all underground facilities. States are approving applications submitted to their agencies by the local One-Call organization for the assignment of the 811 number. The States will need funds to help promote the awareness of this service.

State programs requested $2.2 million in One-Call grant funds during the last application period. This would undoubtedly have been higher if caps were not placed on the amount a state could request, and does not reflect the additional need to promote 811. Grant funding of $2.5 million would adequately fund existing and new needs.

3. Distribution Integrity Management Program Should Provide Additional Safety Improvement.

NARUC is of the opinion that implementing gas distribution integrity management consistent with the findings and conclusions contained in the "Integrity Management for Gas Distribution" report released in December of 2005 and prepared by representatives from NARUC, other government agencies, industry, and public joint work/study groups should provide additional safety improvement. Specifically, this study found that the most useful option for implementing distribution integrity management requirements is a high-level flexible federal regulation in conjunction with implementation guidance developed by the government and industry.

The report finds that a high-level flexible rule requiring distribution operators to formally develop and implement integrity management plans that address the key elements outlined by Department of Transportation Inspector General; understand the infrastructure, identify and characterize the threats, and determine how best to manage the known risks, should be sufficient to address distribution safety enhancements. NARUC members participated in each of the four task teams in the development of the report and on going development of guidance material to assist operators, small and large, in compliance with the proposed rule.

This report was too lengthy to be included in my testimony, however it can be found at: http://www.cycla.com/opsiswc/docs/S8/P0068/DIMP_Phase1Report_Final.pdf

4. NARUC Supports 80% Grant Funding For All Pipeline Safety Programs That Enforce Excavation Damage Prevention Distribution Integrity Inspections and Other Mandated Programs.

NARUC recommends that the present 50 percent reimbursement ceiling contained in federal statute be changed to 80 percent. A State pipeline safety program's cost to enforce damage prevention laws is not presently considered to be allowable costs for the Base Grant. As noted in the Integrity Management for Gas Distribution Report to PHMSA, excavation damage to pipelines was considerably less in States where State pipeline safety programs enforced damage prevention laws. States should be encouraged to place pipeline damage prevention responsibilities within State pipeline safety programs. The cost associated with implementing effective damage prevention programs along with additional resources needed to carry out the core pipeline safety programs justifies the 80 percent funding. This funding level is consistent with other non-pipeline safety grants to States administered by DOT. Providing cost reimbursement of 80 percent to State pipeline programs will allow States to accomplish their pipeline safety responsibilities and provide an important incentive for States to implement effective damage prevention programs, distribution integrity inspections and other mandated programs thus improving the safety of the nation's gas distribution infrastructure.

In the Integrity Management for Gas Distribution Report, the Excavation Damage Prevention Task Group found excavation damage by far poses the single greatest threat to distribution system integrity and is thus the most significant opportunity for distribution pipeline safety improvements. Reducing the threat of excavation damage requires affecting the behavior of persons not subject to the jurisdiction of pipeline safety authorities (i.e. excavators). Federal legislation is needed to support the development and implementation of effective comprehensive State damage prevention programs. Data from the Task Group report over the last 5 years has demonstrated that States with comprehensive damage prevention programs that include effective enforcement experience results in substantially lower rates of excavation damage to pipeline facilities than programs that do not. The lower rate directly translates to a substantially lower risk of serious incidents, accidents, and consequences resulting from excavation damage to pipelines. PHMSA's reaction to the report recommendations has been positive, including the view that the agency should consider providing seed funding to States as an incentive to develop stronger damage prevention programs. The program would be a separate grant fund, apart from funding already being provided under the matching grants or One-Call programs and may be entitled, Excavation Damage Prevention Grant. Once the State takes steps to implement the program, which would be similar to the damage prevention enforcement programs in Virginia and four other States, it would be granted additional funds via the matching grants program. Obviously, the new programs will need funding up to 80% at the beginning for staffing levels to respond to calls and investigations of damages by outside parties. Such funding may be reduced as outside damages are lowered by enforcement. The funds should be provided to State agencies having experience and knowledge in underground utility damage prevention for pipeline safety. The Task Group reviewed several approaches to provide incentives for this program and developed proposed legislation which I have included in this testimony as an attachment.

5. Federally Mandated Installation Of Excess Flow Valves (EFVs) On Service Lines To Customers Is Not Necessary.

A survey performed at the request of NARUC by the National Regulatory Research Institute in July of 2005 supports the majority of State regulatory agencies which are satisfied that operators are installing them where they can be effective. NARUC passed resolutions encouraging federal agencies and legislators to recognize that State officials are well positioned to have knowledge of the operational conditions and circumstances for the installation of these devices and understand that a decision whether or not to install the devices is best determined by the affected State regulatory body.

Distribution Integrity Management Program steering committee members submitted formal comments to PHSMA consistent with other organizations on the installation of these valves. Operational experience verifies that of the thousands of EFVs installed in the past, very few have had false activations. When properly specified and installed, EFVs can reliably interrupt the gas flow under certain conditions when there is an excess flow in the service line. These valves are primarily installed in new and replaced service lines on single family residences where operating pressure is greater than 10 psig. Addressing safety requires an overall approach that allows consideration of all tools and technologies for the various threats to distribution pipelines. EFVs can be used to address the threat of excavation damage for single family residential lines. There may be other tools that can equally or more effectively address this same threat. Therefore, rather than a blanket mandate for installation of EFVs, a provision of Distribution Integrity Management should state that each operator consider the use of EFVs on its own operating system.

Mr. Chairman and members of the Subcommittee, this concludes my remarks. Thank you again for the opportunity to appear before you today and share these views on a most important issue. I will be happy to address any question you may have.

ATTACHMENT

Draft Federal Legislation

§ 60105. State pipeline safety program certifications

Subsection (b) of section 60105 is amended by revising paragraph (b)(4) to read as follows:

> "(4) has or will adopt, within 36 months of [the date of enactment of this amendment], a program designed to prevent damage by excavation, demolition, tunneling, or construction activity to the pipeline facilities to which the certification applies that meets the requirements of section 601XX."
>
> (i) If a state fails to develop and implement an excavation damage prevention program in accordance with item (4), above, the Secretary shall take any action deemed appropriate to ensure an effective damage prevention program within that state.
>
> (ii) Annually, if a state can demonstrate to the Secretary that it has taken all reasonable actions to implement such a program without success, funding for the remainder of its pipeline safety program shall not be affected.

§ 601XX. State damage prevention programs

(a) Minimum standards. In order to qualify for a grant under this section, each State authority (including a municipality if the agreement applies to intrastate gas pipeline transportation) having an annual certification in accordance with section 60105 or an agreement in accordance with section 60106 shall have an effective damage prevention program that, at a minimum, includes the following elements:

(1) Effective communication between operators and excavators- Each state program shall provide for appropriate participation by operators, excavators, and other stakeholders in the development and implementation of methods for establishing and maintaining effective communications between stakeholders from receipt of an excavation notification until successful completion of the excavation, as appropriate.

(2) Fostering support and partnership of stakeholders- Each state program shall include a process for fostering and ensuring the support and partnership of stakeholders including excavators, operators, locators, designers, and local government in all phases of the program.

(3) Operator's use of performance measures – Each state program shall include a process for reviewing the adequacy of a pipeline operator's internal performance measures regarding persons performing locating services and quality assurance programs.

(4) Partnership in employee training – Each state program shall provide for appropriate participation by operators, excavators, and other stakeholders in the development and implementation of effective employee training programs to ensure that operators, the one-call center, the enforcing agency and the excavators have partnered to design and implement training for operators,' excavators' and locators' employees.

(5) Partnership in public education – Each state program shall include a process for fostering and ensuring active participation by all stakeholders in public education for damage prevention activities.

(6) Dispute resolution process – Each state program shall include a process for resolving disputes that defines the state authority's role as a partner and facilitator to resolve issues.

(7) Fair and consistent enforcement of the law- Each state program shall provide for the enforcement of its damage prevention laws and regulations for all aspects of the excavation process including public education. The enforcement program must include the use of civil penalties for violations assessable by the appropriate state authority.

(8) Use of technology to improve all parts of the process – Each state program shall include a process for fostering and promoting the use, by all appropriate stakeholders, of improving technologies that may enhance communications, locate capability, and performance tracking.

(9) Analysis of data to continually evaluate/improve program effectiveness – Each state program shall include a process for review and analysis of the effectiveness of each program element and include a process for implementing improvements identified by such program reviews.

(b) Application. If a State authority files an application for a grant under this section not later than September 30 of a calendar year, the Secretary of Transportation shall review that State's damage prevention program to determine its effectiveness. For programs determined to be effective, the Secretary shall pay 80 percent of the cost of the personnel, equipment, and activities the authority reasonably requires during the next calendar year to carry out an effective damage prevention enforcement program as defined in (a) of this section.

(c) Authorization of Appropriations. There is authorized to be appropriated to the Secretary for carrying out this section [the dollar amount equal to the 80% referenced in (b) above] for each of the fiscal years 2006 through 2010. Such funds shall remain available until expended. Any funds appropriated to carry out this section shall be derived from general revenues and shall not be derived from user fees collected under section 60301.

MR. HALL. I think it is pretty obvious that the gentleman from Virginia is satisfied with the positive response system that he has offered and probably would suggest that as a Federal model, would you?

MR. TAHAMTANI. Mr. Chairman, in a recent study that was completed in December of 2005 on distribution management, I chaired the Excavation Damage Prevention Group within that group that conducted the study. That group came up with the nine elements that I mentioned that have worked for Virginia, so I would believe that any program put together with those nine elements would hopefully produce the results that we have produced in Virginia.

MR. HALL. Do any other States have a similar program?

MR. TAHAMTANI. There are at least three or four other States that have seen a dramatic decrease in their damages as a result of a very active enforcement program, but not all of these States have the nine elements that I mentioned that we have in Virginia.

MR. HALL. You both were interested, in your testimony, in increasing the grant funding for all pipeline safety programs that enforce excavation damage prevention programs from 50 percent, as it is now, to 80 percent. Give us some sense of actual dollar numbers that you are talking about for each State, and how that funding could be applied to enforce excavation damage prevention at the State level. Not in percentages, but in money, in dollars and cents. And how would that money be spent?

MR. TAHAMTANI. I will go ahead, Commissioner Mason, and just talk about Virginia very briefly.

Our damage prevention program, again, is funded by the penalties we collect. So none of that money comes from either the State or the Federal government, and maybe that is very unique in that it keeps it moving along. Now some people don't like that because they think that, well, the more you fine, the more money you have and the more things you can do. That has not been the issue. I started with five investigators in 1996. Today I am down to two, because the damage has gone down. Now we didn't fire the other three. They are full-time trainers. They train about 4,000 contractors a year. We have 41,000 licensed contractors in the State of Virginia, and all of those are not licensed that come in from D.C., Maryland, and other States. So you can see that that program has sort of funded itself, and that is why I believe we have the success we have.

As far as pipeline safety, we help OPS do inspections of the interstate pipelines on the liquid, the oil pipelines. Our program costs about $2 million a year. Forty-one percent of that comes from the grant from the Federal government. This is why we need more grants to assist. In Virginia, that money has never been a problem. Our commissioners support our program. There are a lot of States that match the grant that the Federal government provides, so if you give them $50,000, they only match it by $50,000. They need your help, and this is why we are recommending that the funding be increased from 50 to 80 percent.

MR. HALL. Commissioner Mason?

MR. MASON. Mr. Chairman, that is a great question, and going to the point of perhaps even using the grant money to create seed money, sir, that the program can be up and running. Then as you have excavation damage and subsequent fines that can continue to refund almost on a rotary or a revolving basis, but you really need, initially, at least, for the seed money to be there so that a State can get a program up and running. It is almost like running any business. It costs money to get in business before you can open the door.

MR. HALL. All right. I recognize the gentleman from Virginia, Mr. Boucher.

MR. BOUCHER. Well, thank you very much, Mr. Chairman.

And Mr. Tahamtani, did I get that correct?

MR. TAHAMTANI. Yes, sir.

MR. BOUCHER. Yes, that is good.

Let me thank you for taking part in our hearing today and congratulate you on the success that you are having in Virginia. You are getting accolades all of the way around. I think you heard on the first panel a general consensus that Virginia's program leads the Nation in preventing damage from excavation. And we are all in agreement that it is a model that would usefully be replicated elsewhere. I think the key question that we have is what we might be able to do, perhaps in our reauthorization of the 2002 statute, that could encourage other States to adopt Virginia's program, or at least the essential elements of it.

And so I would ask both of you if you have any suggestions for us that we could incorporate in the statutory revision that we intend to make that would have the effect of having every State celebrate their experience to the level that Virginia is.

Mr. Mason, do you have any suggestions?

MR. MASON. I don't know specifically what I can recommend to Congress. I know what we do, as States, is try to put on sessions. Three times a year our association meets. We try to take best practices and sort of inform and educate other commissioners as to what is going well. And Virginia does have a great program. I know our staff and others have worked with them to understand it. But yes, it takes funding to get to that next level so that we can make a good program, you know, the best available technology, so to speak, go statewide. As we mentioned earlier in our testimony, it really does take Federal funding proportionate and equal to what State funding you have there, so I really believe that if Congress appropriates the amount we recommend, then we can take it to the next level and work across the State jurisdictional and commonwealth jurisdictional lines.

MR. BOUCHER. Let me ask you why funding is essential to this. Virginia developed its program based on resources then available. Why can't other States do the same? Why does money have to flow from the Federal Government in order to make that happen?

MR. MASON. Well, that is somewhat of a loaded question, because that would mean I would have to identify States that are destitute or not as well off as Virginia, but in fact, not every State has a growing population and those kinds of things, such as Virginia. Many States are in economic decline. And when the State General Assembly is trying to allocate their funds in everything from education to medical issues, social and medical issues, and so without grant money to match State money, this has received the lower priority.

MR. BOUCHER. Okay. Well, that is a point very well taken.

So let me ask you, Mr. Tahamtani, do you have any statutory recommendations for us, I mean, changes in the law that might be helpful in this respect?

MR. TAHAMTANI. Mr. Boucher, as I indicated, I participated in this very lengthy study last year that has been submitted to the Office of

Pipeline Safety, its gas distribution integrity management. We all know that excavation damage is the leading cause of pipeline accidents and failures, so our group spent a lot of time coming up with ways to help all States improve their damage prevention program. And we also put some language together to give the Secretary the authority to encourage the States with some seed money first and some after to ensure that they are moving forward with State laws. It is going to take good State laws to make this happen at the State level.

The fact that Virginia, I guess, from the very beginning used their funds to go back to the public, that has helped. They don't think of this as a way to balance the State budget. This money goes back into the program, and that has helped our program.

MR. BOUCHER. Okay. Well, that answer doesn't quite get at the question. I guess at one extreme, we could simply suggest that maybe we ought to have a Federal statute that says here are nine elements that every State should adopt in order to prevent excavation damage. We would probably be legislating that with greater certainty than we generally have when we embark upon a statutory exercise because we have the Virginia program that is a model, based on those nine elements, that, in the opinion of virtually everyone, has succeeded extraordinarily well, better than any other State in the country.

So I think I can anticipate your answer, but why should we not simply do that?

MR. TAHAMTANI. What I mean here is that our group proposed that you do exactly that.

MR. BOUCHER. Oh, that we do that?

MR. TAHAMTANI. Yes.

MR. BOUCHER. So in other words, we have a Federal statute that says every State shall have a program that adopts the following nine elements. Period. And then we provide some grant funds to help States with implementation.

MR. TAHAMTANI. Exactly.

MR. BOUCHER. So that is your proposal?

MR. TAHAMTANI. Yes.

MR. BOUCHER. Mr. Mason, do you agree with that?

MR. MASON. Mr. Boucher, I guess, just because I represent an organization, so I will answer that based on my viewpoint. Having a flexible Federal recommendation is very good. It still gets down to the bottom line of whether there will be sufficient funding at the State level. I think we include in our testimony, for example, a survey of States on what kind of funding they will use for their programs. And really, only a couple actually use GRF. Almost every one of them use some sort of a formula based on some sort of a fee. So the bottom line is, if there is a flexible Federal requirement encouraging those nine points or other points, or you know, somewhere around that guideline, that would help in a long way to where State GPS programs could then work through their system to try to get, again, match money for Federal match money, because I think your State legislature is going to know that they are partnering with the Federal government. In other words, if the flexible requirements are coming from the Federal side, it needs to have money to match the State money, because there only two that I can find that use GRF.

MR. BOUCHER. Okay. Well, your answer sort of comes back to money again. I gather your recommendation to us falls somewhat short of Mr. Tahamtani's in terms of the statutory requirement that the Federal government would make. You are not prepared to endorse, at this point, a Federal statute that would simply say each State must adopt a program that relies upon these nine principles? You are not willing to go that far, is that correct?

MR. MASON. And the reason I am not willing to go that far is my experience at NARUC is a lot of States are willing to do something, but truly they like to have it as a State decision and not Federal mandates. And I have run into this on other issues and I am dealing with our pipeline taxation issue right now. It is just a lot of people like seeing the light; they just don't like being drawn with a noose around their neck to it.

MR. BOUCHER. All right. Well, Mr. Mason, do you think NARUC would be willing to work with us over the coming month or so on an appropriate Federal statutory provision that your organization, perhaps, could then endorse?

MR. MASON. I could go so far as to say we could put workshops on sponsor resolution and try to inform and educate the membership.

MR. BOUCHER. Right, but the question I am asking you, will you work with this committee--

MR. MASON. Oh, absolutely.

MR. BOUCHER. --in order to help us derive an appropriate statutory provision for whatever changes we decide to make in the 2002 law that addresses this concern?

MR. MASON. I would be happy to work with the committee, and we have had a great working relationship with DOT, with PHMSA, and its predecessor, so absolutely.

MR. BOUCHER. All right. Very good. Thank you very much.

Thank you, Mr. Chairman.

MR. MURPHY. [Presiding] Thank you.

The Chairman will recognize himself for 5 minutes here.

A question to Mr. Tahamtani. With regard to the Virginia model you had mentioned that it reduced incidents by 50 percent. How did it do in terms of preventing injuries from breaches of pipeline? Do you know what that rate was?

MR. TAHAMTANI. Since 1996, again, when we began the mandatory reporting, we had one death. A woman had called, so the public education was working, and the marking was supposed to happen by Wednesday. The locator called and requested an extension to Friday. They marked it on Friday. They mismarked the gas line. On Saturday morning, when he started his saw in the basement, he had a house looking like this, and he died three weeks later.

That particular case, we took it to the commission and went through our process, and they did a very, very good case. As a result of that, that locator company is now out of business. So we have had one death since 1996, so--

MR. MURPHY. But in terms of reduction of injuries, though?

MR. TAHAMTANI. We have not had any injuries.

MR. MURPHY. In this now, you have heard earlier, we were talking about Minnesota had a change to require notification to 911 when there is a breach. Does Virginia have any equipment law with regard to notifying anybody when there is a--

MR. TAHAMTANI. I knew you would ask that question, so here is my law. If the damage, this location, or disturbance in the underground utility facility creates an emergency, and this is defined in our law something that impacts life, property, and so on and so forth, the person responsible for the excavation and demolition shall, in addition to complying with subsection D, which means calling the gas company, in this case, take immediate steps to reasonably safeguard life, health, and property. Now that is enforceable by our commission, so when we see that they have not done that, obviously penalties are used to encourage that. We haven’t had any problems.

MR. MURPHY. That seems broadly defined, I mean, with regard to taking steps to secure life and property. Is that interpreted to mean they notify the police or the fire department? And what mechanism do they have to go through to do that?

MR. TAHAMTANI. We have got a county, Fairfax County, not far from here, that they monitor all of the 911 or all of the damages and they appear because of the way they want to run their emergency response in the county, that under that provision I believe that it is flexible enough. The other piece of this is that we are out there educating excavators. This is what you do when you have got a damage. If you have got a nick to the pipeline and no gas releases, this is what you do. If the gas is released, this is what you do. So excavators have actually evacuated the area before even calling 911.

MR. MURPHY. Mr. Mason, would you know what some of those are with regard to how States are managing this when there is an actual release when a pipeline is breached?

MR. MASON. The language, of course, varies from jurisdiction to jurisdiction. I don't know of any that actually have language that says the magic numbers 911. It goes back to the issue of notifying proper authorities and company personnel. That seems to be the--

MR. MURPHY. You were not here earlier, you were caught up in traffic, when I was showing a picture of this home where the rule in Pennsylvania was similar. You notify someone and they notify the local municipality, but no one was in the local municipality, and so it came via fax to an empty room. And I understand there is a variation between States and how they notify. And my concern is that if it simply says they take reasonable steps and the local reasonable step is you send a fax, that is not going to save lives. And so part of the question I asked the previous panel, and hope it is something you can help me with, too, by giving the two areas that each of you have expertise and jurisdiction in to help us understand and know what different States do and what would be an effective model. The Virginia model sounds like it is working pretty well with reducing and preventing the breach in the first place. But once it does occur, my question is how can we require the States to have some reasonable rules, which also are sensitive to the vast differences in, for example, rural areas versus urban areas and the size of the pipe and the type of the leak, et cetera. So that is something I wouldn't expect you all to have full knowledge of now, but if your associations could help get information back to the Chairman on this, I would be very grateful for that.

MR. MASON. Mr. Chairman, it is difficult to talk about, you know, cases in specific, and especially those ones that are in litigation. One of the biggest issues we have, though, is when there has been possible damage, and a lot of times you don't know of the leak at the time, and then a subsequent slow leak that eventually causes the fire or, you know, something along that line. So you have that whole range of things happening right now with a flash or with a leak you can hear to something that creates a slow enough leak that you may not know that it, you know, runs along the pipe into a home.

MR. MURPHY. Along those lines, when someone is doing excavating as a subcontractor or someone else is drilling, in this case they were doing horizontal drilling, and I guess they not only punctured a gas line, but they punctured the drain line to the house, in situations like this, is it required that the excavators have with them equipment to monitor for gas leaks?

MR. MASON. I am not aware that it is, Mr. Chairman.

MR. MURPHY. So how would they know, when you say it is a slow leak or a medium leak? Basically, would they only know if they smell it? I mean, I am assuming when someone is going through a neighborhood to detect any kind of gas leaks, then you would be searching for leaks that perhaps are so small they would not be sensitive to the human nose to pick that up. And if we don't require them to have any kind of monitoring equipment, and yet they are drilling or excavating in an area that has pipelines and concerned enough to call 811- or some other system, how would we even know if they broke a line?

MR. TAHAMTANI. Well, again, the gas is odorized, so the first thing is the sense of smell and, as I mentioned, the odor had been stripped off of the gas, because it migrated through soil to the basement of the house, of course, hearing, and the actual damage. But no law that I know of requires excavators to carry gas-detecting equipment to monitor the gas leaks. If something is nicked and it is covered up and the gas migrates, then we all hope that everything goes right and people smell the gas and respond properly to make sure nothing happens.

MR. MURPHY. But you just said that that odor may be stripped off as it migrates through the soil.

MR. TAHAMTANI. It can get stripped, yes.

MR. MURPHY. Can that still be detected if someone has the monitoring equipment, such as what gas companies go through neighborhoods with?

MR. TAHAMTANI. Right.

MR. MURPHY. You said, as far as you know, however, no one is required to have that equipment with them?

MR. TAHAMTANI. For excavators.

MR. MURPHY. For excavators. All right. I see my time is expired.

And Mr. Burgess here from Texas is recognized for 5 minutes. Thank you.

MR. BURGESS. Thank you, Mr. Chairman.

I apologize for missing most of the hearing. There was another hearing going on downstairs.

Just for a point of reference, I live in this green spot here in Texas. It is called the Barnett Shale. And I really don't have a lot of questions, because, again, I did miss most of this, but I do want to ask you, Mr. Mason. You made reference to the fact that if the point of distribution was too close to the production facility, that that could gum up the works. I think that is the technical term that you used.

MR. MASON. Very technical, Mr. Congressman. I work with Mary McDaniel. Well, I believe she was the director of the Gas Pipeline Safety Program at the Texas Railroad Commission. We were trying to scope when an EFV should be used and when it, perhaps, wouldn't be prudent. Basically, now the EFVs work well, about 10 pounds per square inch. One of the caveats, though, is there is concern if the natural gas has constituent qualities, and I would hear people use the term "contamination." I don't like using that word, because that implies, to me, something from outside. And for 9 years, by the way, I was the Chief of the Division of Oil and Gas. I oversaw oil and gas production in the State of Ohio Environmental Enforcement. So when I hear the word "contamination," that, to me, is something that is not indigenous to the natural gas itself. But in production areas, through the Appalachians, obviously Texas, and other places, you do have some of the heavier gases that, as the gas moves and cools, could, in fact, drop out. Perhaps there is a better term than "gum up," but in fact, what we are talking about is interfering with the normal operation of the EFV itself. Again, those are the concerns we have on what would be called a mandatory mandate. We want to make sure anything that was put in place operated well, regardless of the constituents, as well as above 10 p.s.i. As far as the p.s.i. goes, you know, 5 years from now, a year from now, it could be five p.s.i. That is based on the development of technology on the EFVs.

MR. BURGESS. Well, is the concern there because of the relationship between volume, temperature, and pressure, or is it because of the presence of other substances in the gas as it recently comes out of the well?

MR. MASON. It is my understanding, as you know, and this is the way it has been in Ohio, but with a little experience in the Southwest, but a lot of times, the heavier gases were stripped out for sale, and that is fine when you are moving natural gas from Oklahoma or Texas into Ohio or into the Northeast, and that does happen. But frankly, gas systems are located close enough to the well fields that you are really getting gas fairly directly from the well fields, and so it has been explained to me from my counterparts in Texas that one of the concerns they have is they want to make sure if, for example, there was a requirement for an EFV that it would actually operate well in all conditions of natural gas, again in the Northeast as well as in the Southwest.

MR. BURGESS. So we do have, because of the geologic peculiarities of the Barnett Shale, that gas is harvested by hydraulic fracturing, and so we have ended up poking a lot of holes in that geologic formation to recover the gas.

Another issue with the Barnett Shale is that it is sited underneath what is largely, in some instances, a very developed and populated area.

Of course, with lateral drilling, they are able to recover more of a gas, but are there special considerations that need to be taken with this type of geologic formation that is under an area that is relatively populated?

MR. MASON. I am not aware of any. And of course, we have had, you know, a lot of drilling within urban areas for a lot of years, and the biggest safety issues always get down to set back from tank batteries and things of that nature, anywhere you might have vapors. But that has nothing to do with the distribution system, per se. That is the production side, and of course, Texas has the Texas Railroad Commission and I think their own DEQ or DNR, and I think there are three agencies involved in Texas that do a good job.

MR. BURGESS. Thank you, Mr. Chairman. I will yield back.

MR. MURPHY. Thank you very much.

If there are no more questions, we will dismiss this panel.

And we invite the third panel forward.

We are just going to hold for one second. We are trying to locate the Chairman and ask him a quick question. Thank you. Just relax. Here he comes now.

MR. HALL. We use the two-platoon system here. Thank you for chairing, Tim.

Okay. We thank this third group for taking position. Mr. Bender, who is Vice President of Gas Distribution and New Business Division, Baltimore Gas and Electric Company, we recognize you for 5 minutes or less to go over your testimony and then subject yourself to some questions. Thank you.

STATEMENTS OF EDMUND F BENDER, JR., VICE PRESIDENT, GAS DISTRIBUTION AND NEW BUSINESS DIVISION, BALTIMORE GAS AND ELECTRIC COMPANY, ON BEHALF OF AMERICAN GAS ASSOCIATION; JERYL L. MOHN, SENIOR VICE PRESIDENT, OPERATIONS AND ENGINEERING, PANHANDLE ENERGY, ON BEHALF OF INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA; TIMOTHY C. FELT, PRESIDENT AND CEO, EXPLORER PIPELINE COMPANY, ON BEHALF OF ASSOCIATION OF OIL PIPELINES; LOIS N. EPSTEIN, P.E., SENIOR ENGINEER, OIL AND GAS INDUSTRY SPECIALIST, COOK INLET KEEPER, ON BEHALF OF PIPELINE SAFETY TRUST; AND BOB KIPP, PRESIDENT, COMMON GROUND ALLIANCE

MR. BENDER. Thank you, Mr. Chairman. Good morning.

I would like to thank the committee for convening this hearing on the important topic of pipeline safety.

My name is Frank Bender. I am Vice President of Gas Distribution and New Business of Baltimore Gas and Electric Company. We are a subsidiary of Constellation Energy. BGE delivers natural gas to 634,000 customers in Maryland.

I am testifying today on behalf of the American Gas Association and the American Public Gas Association. Together, AGA and APGA represent more than 850 local natural gas utilities serving almost 56 million customers nationwide.

The Pipeline Hazardous Material Safety Administration and the industry have made significant progress on the initiatives mandated by the 2002 Pipeline Safety Act.

In our opinion, only minor adjustments should be considered at this point. Our companies have identified only one major area we believe requires considerable improvement, and that is excavation damage prevention.

Congressional attention to more effective State excavation damage programs can, and will, result in real, measurable decreases in the number of incidents occurring on natural gas distribution pipelines each year. Excavation damage is the single cause of a majority of the natural gas distribution pipeline incidents.

Understandably, most of our customers think that all pipelines are alike. There are, however, significant differences between liquid transmission systems, natural gas transmission systems, and natural gas distribution systems, which are operated by local gas utilities.

Gas distribution utilities bring the natural gas service to our customers’ front doors. Each type of pipeline system faces different challenges, operating conditions, and consequences from incidents.

Federal regulations recognize the differences between distribution pipes and other types of pipelines, and different sets of rules have been created for each. At the same time, State regulators, who have direct oversight over distribution operators, are regularly inspecting or reviewing our operations.

Our industry commitment to safety extends beyond government oversight. We continually refine our safety practices. Natural gas utilities spend an estimated $6.4 billion each year in safety-related activities. Our industry’s commitment to safety is borne out each year through the Federal Bureau of Transportation Statistics’ annual figures.

Now there are two kinds of incidents involving natural gas distribution systems, and if you can look at the chart on my left: first, those caused by factors the pipeline operator, to some extent, can control, such as improper welds, material defects, incorrect operation, corrosion, or excavation damage by our own contractors. And secondly, those caused by factors the pipeline has little or limited ability to control, such as excavation damage by a third party, earth movement, structure fires, floods, vandalism, and lightning.

The record shows that between 2001 and 2005, 82 percent of all reported incidents were the result of excavation damage by third party or other factors the utility company had little or no control over. In many cases, the typical little-or-no-control incident involves a party outside the jurisdiction of authorities overseeing pipeline safety.

You have heard several times today that excavation damage represents the single greatest threat to distribution system safety, reliability, and integrity. The nationwide education program on the three-digit, one-call dialing to prevent excavation damage is a step in the right direction, but more is needed. Data from the last 5 years demonstrates that States that have stringent enforcement programs experienced a much lower rate of excavation damage to pipeline facilities than States that do not have these stringent enforcement powers. And again, if you look at the chart, that demonstrates that point with Virginia and Minnesota actually leading the way much better than States without enforcement programs.

A comprehensive damage prevention program includes not only education, but also effective enforcement. Currently, the U.S. Department of Justice is responsible for enforcing Federal infrastructure damage prevention statutes with regard to parties conducting excavations. Most unfortunately, the Department has rarely exercised such authority.

Programs such as Virginia's and Minnesota's show that nine key elements must be present and functional for the damage prevention program to be effective. And this chart shows specifically those nine elements.

AGA and APGA recommend that Congress modify existing law to insert a new section outlining these nine elements and providing for additional funding for implementation of the program. Such funding should be allocated directly to each State agency having oversight over pipeline safety. AGA and APGA also support providing continued funding authority for grants to States to support one-call programs and for partial funding of the Common Ground Alliance damage prevention organization.

The statistics are clear: excavation damage prevention represents the single greatest opportunity for distribution safety enhancements, and we urge Congress to take decisive action on this front.

Turning now to distribution system integrity, we have been participating in a team with all members of a joint Federal, State, industry, and public stakeholder group to work towards completion of the distribution integrity management rule by PHMSA. Thus, industry and government stakeholders are working collaboratively on their own initiative to improve the safety of the Nation's distribution lines. We believe that this process is moving forward successfully and should be continued without further legislative imperatives.

This distribution integrity management stakeholder group also found that federally-mandated installation of excess flow valves on service lines to customers is not appropriate. It did, however, suggest that operators be required to perform a risk assessment and outline risk criteria for installation of the excess flow valves.

It is our hope that in evaluating the appropriateness of the 7-year reinspection requirement, the U.S. Government Accountability Office will uncover all of the pertinent facts and that, based on those findings, Congress will consider options for allowing a change to the interval that would be consistent with those findings. This will allow operators to continue to deliver natural gas safely and affordably.

In summary, AGA and APGA believe that Congressional passage of pipeline safety reauthorization this year will result in timely and significant distribution system safety improvements. The members of AGA and APGA emphatically support the recommendation that Congress enact legislation that gives States an incentive to adopt stronger damage prevention programs.

Thank you for the opportunity to appear here today.

[The prepared statement of Edmund F. Bender, Jr. follows:]

PREPARED STATEMENT OF EDMUND F. BENDER, JR., VICE PRESIDENT, GAS DISTRIBUTION AND NEW BUSINESS DIVISION, BALTIMORE GAS AND ELECTRIC COMPANY, ON BEHALF OF AMERICAN GAS ASSOCIATION

Summary

The natural gas utility industry is proud of its safety record. Natural gas has become the recognized fuel of choice by citizens, businesses and the federal government.

Public safety is the top priority of natural gas utilities. We invite you to visit our facilities and observe for yourselves our employees' dedication to safety. We are committed to continuing our efforts to operate safe and reliable systems and to strengthening One-Call laws and systems in every state.

AGA and APGA believe that Congressional passage of pipeline safety reauthorization this year will result in timely and significant distribution system safety improvements. Further, because of the wide variety of distribution systems across the U.S, promulgation of a distribution integrity regulation by PHMSA may yield effective enhancements in distribution safety if PHMSA allows gas utilities risk-based options to address threats to pipeline integrity in their specific systems and situations.

Despite the fact that our members, when undertaking excavation themselves, would have to also abide by the provisions of an enhanced state damage prevention program, the members of AGA and APGA emphatically endorse the recommendation that Congress enact legislation that incentivizes states to adopt stronger damage prevention programs. By doing so, all states could realize a significant, marked reduction in incidents on distribution lines.

Thank you for providing the opportunity to present our views on the important matter of pipeline safety. To reiterate, since the passage of the 2002 Pipeline Safety Act, PHMSA and the industry have made significant progress – and now we urge you to go a step further in that positive direction by addressing excavation damage. We feel confident overall in reporting today that, other than this issue, the pipeline safety program is going well.

Good morning, Mr. Chairman and members of the Committee. I am pleased to appear before you today and wish to thank the Committee for calling this hearing on the important topic of pipeline safety. My name is Frank Bender. I am vice president of Gas Distribution and the New Business Division of Baltimore Gas and Electric Company, a subsidiary of Constellation Energy. BG&E delivers natural gas to 634,000 customers in an 800 square mile area in Baltimore and surrounding areas in Central Maryland. Our company is proud of its heritage as the first gas utility in the United States, tracing its history back to 1816.

I am here testifying today on behalf of the American Gas Association (AGA) and the American Public Gas Association (APGA). AGA represents 197 local energy utility companies that deliver natural gas to more than 56 million homes, businesses and industries throughout the United States. AGA member companies account for roughly 83 percent of all natural gas delivered by the nation's local natural gas distribution companies. AGA is an advocate for local natural gas utility companies and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international gas companies and industry associates.

APGA is the national, non-profit association of publicly owned natural gas distribution systems. APGA was formed in 1961, as a non-profit and non-partisan organization, and currently has 655 members in 36 states. Overall, there are approximately 950 municipally owned systems in the U.S. serving nearly five million customers. Publicly owned gas systems are not-for-profit retail distribution entities that are owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities.

I hope that my testimony will provide you with a better understanding of natural gas distribution systems, their regulatory setting, what is being done to further enhance their safety and how together we can build upon the excellent record of safety natural gas utilities have established.

The last reauthorization of pipeline safety resulted in several significant mandates and initiatives aimed at enhancing safety. Since the passage of that bill in 2002, the Pipelines and Hazardous Materials Safety Administration (PHMSA) and the industry have made significant progress on each of those initiatives, and the record shows that things are proceeding very well, with only a few minor adjustments to be considered. In fact, our companies have identified only one major area we believe requires considerable improvement: excavation damage prevention. Our companies believe your attention to more effective state excavation damage programs can, and will, result in real, measurable decreases in the number of incidents occurring on natural gas distribution pipelines each year. Although I will speak today on a number of issues the industry has considered in terms of further enhancing the safety record of natural gas pipelines, I will spend the majority of my time addressing excavation damage, which is the cause behind the majority of natural gas distribution pipeline incidents, and the need for Congress to provide an incentive for states to adopt stronger damage prevention programs.

Gas Distribution Utilities Serve The Customer

In order to understand how distribution safety can be enhanced, it is first important to understand the function and structure of distribution pipelines.

Distribution pipelines are operated by natural gas utilities, sometimes called "local distribution companies" or LDCs. The gas utility's distribution pipes are the last, critical link in the natural gas delivery chain. To most customers, their local utilities are the "face of the industry". Our customers see our name on their bills, our trucks in the streets and our company sponsorship of many civic initiatives. We live in the communities we serve and interact daily with our customers and with the state regulators who oversee pipeline safety. Consequently, we take very seriously the responsibility of continuing to deliver natural gas to our communities safely, reliably and affordably.

The Difference in "Pipelines"

Understandably, most customers lump all "pipelines" together, however, there are indeed significant differences between liquid transmission systems, natural gas transmission systems and natural gas distribution systems operated by local gas utilities. Each type of pipeline system faces different challenges, operating conditions and consequences of incidents.

Interstate transmission systems are generally long, straight runs of large diameter steel pipelines, operated at high volumes and high pressures. These larger transmission lines feed natural gas to the gas distribution utility systems.

Gas distribution utility systems, in contrast, are configured like spider webs, operate at much lower volumes and pressures and always carry gas that has been odorized for easy leak detection. Distribution pipeline systems exist in populated areas, which are predominantly urban or suburban.

Distribution pipelines are generally smaller in diameter (as small as 1/2 inch), operate at pressures ranging upward from under one pound per square inch, and are constructed of several kinds of materials including a large amount (over 40 percent) of non-corroding plastic pipe. Distribution pipelines also have frequent branch connections, since most customers require individual service lines. Most distribution systems are located under streets, roads, and sidewalks and, when working on them, care must be taken not to disrupt the flow of traffic and of commerce unnecessarily. Because distribution pipelines provide a direct feed to customers, the use of in-pipe inspection tools usually requires natural gas service to customers to be interrupted for a period of time.

Utility system customers play a unique role in identifying and reporting gas odors. At BG&E, our 610,000 customers serve as early alert systems, by monitoring for odors that may indicate an unsafe condition and promptly calling our call center. For these reasons, gas distribution utility systems are quite different from transmission systems.

Federal regulations recognize the differences between these types of pipelines, and different sets of rules have been created for each. 49 CFR Part 192 sets out the regulations for natural gas transmission and distribution pipelines and the rules distinguish between the two, while 49 CFR Part 195 sets out the regulations for liquid transmission lines.

Regulatory Authority

As part of an agreement with the federal government, most state pipeline safety authorities have primary responsibility for natural gas utilities as well as intrastate pipeline companies. However, state governments have to adopt as minimum standards the federal safety standards promulgated by the U.S. Department of Transportation (DOT.) In exchange, DOT reimburses the state for up to 50% of its pipeline safety enforcement costs. Therefore, the actions of Congress affect state regulations and our companies. The states may also choose to adopt standards that are more stringent than the federal ones, and many have done so. BG&E and many other distribution system operators are in close contact with state pipeline safety inspectors. As a result of these interactions, distribution facilities are subject to more frequent and closer inspections than what is required by the pipeline safety regulations.

Natural Gas Utilities Are Committed to Safety

Our commitment to safety extends beyond government oversight. Indeed, safety is our top priority -- a source of pride and a matter of corporate policy for every company. These policies are carried out in specific and unique ways. Each company employs safety professionals, provides on-going employee evaluation and safety training, conducts rigorous system inspections, testing, and maintenance, repair and replacement programs, distributes public safety information, and complies with a wide range of federal and state safety regulations and requirements. Individual company efforts are supplemented by collaborative activities in the safety committees of regional and national trade organizations, such as the American Gas Association, the American Public Gas Association and the Interstate Natural Gas Association of America.

We continually refine our safety practices. Natural gas utilities spend an estimated $6.4 billion each year on safety-related activities. Approximately half of this money is spent in complying with federal and state regulations. The other half is spent for our companies' voluntary commitment to ensure that our systems are safe and that the communities we serve are protected.

Our industry's commitment to safety is borne out each year through the federal Bureau of Transportation Statistics' annual figures. Delivery of energy by pipeline is consistently the safest mode of energy transportation. Natural gas utilities are dedicated to continuing to improve on this record of safe and reliable delivery of natural gas to our customers.

What Are The Facts About Gas Distribution Safety Incidents?

As part of our commitment to safety, through the DOT pipeline statistic database gas utility trade associations monitor the number and causes of all reportable incidents on the nearly 2-million mile natural gas distribution system. An examination of DOT's statistics tells a tale of two trends.

A comparison of reportable incidents along the natural gas distribution system between 2001 and 2005 is depicted in the chart labeled Exhibit 1. The chart highlights the existence of two different types of incidents: those caused by factors the pipeline operator can directly control (such as improper welds, material defects, incorrect operation, corrosion or excavation damage by a utility contractor); and those caused by factors the pipeline has little or limited ability to control (such as excavation damage by a third party, earth movement, structure fires, floods, vandalism and lightning).

The record shows that between 2001 and 2005, 82 percent of all reported incidents were the result of excavation damage by a third party or other factors the utility company had little or no control over. The number of incidents operators could possibly control remained a small portion of overall incidents. In addition, statistics show that it is incidents caused by factors beyond the control of pipeline operators that are on the increase, with more reported incidents every year except 2002. (The dip in 2002 is attributed to a slowdown in construction-related activities associated with the post-9/11 downturn in the economy.)

In many cases, the typical "little or no control" incident involves a local excavator who has decided to expedite an excavation project at the calculated risk of hitting a line. The excavator's actions, while irresponsible and risky, generally lie outside the jurisdiction of PHMSA. Given that willful negligence is generally difficult to prove and despite efforts by PHMSA, pipeline operators and others to educate excavators about the need for safe digging practices, third party excavation damage remains the single largest cause of incidents along the natural gas distribution system, accounting for almost half (48 percent) of incidents beyond the utility's ability to control. Pipeline operators recognize the need to change this risky behavior in order to protect their lines and have used educational efforts to help raise awareness about the need for safe practices, but with a limited effect.

As the data demonstrates, the most effective way to minimize safety incidents on our distribution lines is to make incidents caused by excavation damage an endangered species. Congress has long recognized that excavation damage to gas and hazardous liquid pipelines is a major safety concern. This was the major reason for passage of damage prevention legislation passed in 1999 with the Transportation Equity Act of the 21st Century and in 2002 with the Pipeline Safety Improvement Act. These measures have made a substantial contribution toward decreasing the number of incidents**;** but more can be done, with your continued support.

How Can the Distribution Integrity Process Affect Pipeline Safety Reauthorization?

Since the passage of the 2002 Pipeline Safety Improvement Act, AGA and APGA member companies that also operate natural gas transmission pipelines have been resolutely implementing the requirements of the gas transmission integrity rule. It is a learning process for both operators and inspectors as together they proceed through the various steps of the implementation process. When PHMSA decided to promulgate the transmission rule, AGA and APGA stated that our members supported taking a responsible course of action in seeking to enhance transmission pipeline integrity. Our members continue to believe that such a course of action will yield safety benefits, as a result of the transmission integrity regulation.

Last year, PHMSA embarked on a new initiative to develop a regulation governing distribution integrity management programs (DIMP). Again, AGA and APGA member companies have fully supported taking a responsible course of action in seeking to enhance distribution pipeline integrity. As a starting point for distribution system regulation, PHMSA has followed the directives of the DOT Inspector General and the findings of a joint federal, state, industry and public stakeholder group that met for one year. Those findings are presented in the report *Integrity Management for Gas Distribution, Report of Phase 1 Investigations* released in December of 2005. The DIMP stakeholder group found that to achieve distribution safety enhancements while ensuring continued reliable delivery of gas at an affordable cost to customers, a high-level flexible rule should be promulgated by PHMSA requiring each operator of a gas distribution system to develop and implement a formal integrity management plan that addresses key elements outlined by the DOT Inspector General. The group also found that this rule should be implemented in conjunction with a nationwide education program on 3-digit One-Call dialing, plus continuing R & D.

First and foremost, the stakeholder group determined that the wide differences between gas distribution pipeline systems operated across the U.S. make it impractical simply to apply the integrity management requirements for gas transmission pipelines to distribution. The diversity among gas distribution pipeline operators also makes it impractical to establish prescriptive requirements that would be appropriate for all circumstances. Over half the distribution operators that will be affected by this rule are small entities – city owned utilities that serve fewer than one thousand customers and have revenues less than one million dollars per year. Thus, it is important that any rule not impose a one-size-fits-all approach. The DIMP stakeholder group found that it would be most appropriate to require that all distribution pipeline operators, regardless of size, implement an integrity management program that would contain seven key elements:

1. Develop and implement a written integrity management plan.
2. Know its infrastructure.

3. Identify threats, both existing and of potential future importance.
4. Assess and prioritize risks.
5. Identify and implement appropriate measures to mitigate risks.
6. Measure performance, monitor results, and evaluate the effectiveness of its programs, making changes where needed.
7. Periodically report performance measures to its regulator.

These seven elements will be clarified by way of guidance being developed by a nationally recognized standards body to provide a basis for operator compliance and for regulator enforcement. The DIMP stakeholder group found that this guidance should also focus on ways of verifying the effectiveness of an operator's leak management program as an essential element of a risk-based distribution integrity management approach.

AGA and APGA are committed to working with all stakeholders with a goal of completing the distribution integrity management rule by PHMSA early next year.

The DIMP stakeholder group also found that federally mandated installation of excess flow valves on service lines to customers is not appropriate under the distribution integrity regulation. State, industry and public members of the DIMP stakeholder group submitted formal comments to PHMSA recommending that operators who choose not to voluntarily install excess flow valves in all circumstances should instead develop a process whereby the installation of these valves for specific service lines is based on defined risk criteria. The members of this stakeholder group outlined decision criteria for installation of the valves, also concluding that, depending on the situation, there may be more effective methods for controlling the risk to a service line.

AGA does not support federally mandated installation of excess flow valves; nor does such a mandate have the support of the majority of state safety regulatory agencies, many of which are satisfied that operators are installing them where they can prove to be effective. Indeed, the National Association of Utility Regulatory Commissioners (NARUC) and the National Association of Pipeline Safety Representatives (NAPSR) have passed resolutions to that effect. Many utilities already install these valves voluntarily, and the number is expected to grow.

At the same time, over the past several years, AGA has facilitated forums with industry and regulators to ensure dissemination of the most up-to-date operational information about excess flow valves. We believe that operators now have the information needed to determine if these valves would be effective for their systems. Combined with the proposed risk-based criteria, the operator's decision on whether to install the valves would have a sound technical basis to provide such protection where it is most appropriate.

Excavation Damage – The Big Threat to Distribution Pipelines

With that, we turn again to excavation damage on natural gas distribution lines. As the distribution safety statistics have repeatedly shown, excavation damage represents the single greatest threat to distribution system safety, reliability and integrity. Although the nationwide education program on the three-digit One-Call dialing to prevent excavation damage, together with the DIMP rule, is a step in the right direction, the DIMP stakeholder group found that more is needed.

Gas pipeline facility operators are required to have damage prevention programs under current DOT regulations. However, preventing excavation damage to gas pipelines is not completely under the control of such operators. Reducing this threat requires affecting the behavior of persons not subject to the jurisdiction of pipeline safety authorities (e.g. excavators working for entities other than pipeline facility owners/operators). Pipeline facility operators currently approach this through educational efforts.

Data from the last five years has demonstrated that states, such as Minnesota, Virginia, Georgia, Connecticut and Massachusetts have experienced a substantially lower rate of excavation damage to pipeline facilities than states that do not have stringent enforcement powers and/or programs. I have brought along a chart that compares the measurable results of effective programs in Virginia and Minnesota against the results in a state where the absence of some key processes precludes an effective program (Attachment 2). The lower rate of excavation damage translates directly to a substantially lower risk of serious incidents on gas and hazardous liquid pipelines and avoided consequences resulting from excavation damage to pipelines.

The DIMP stakeholder group explored a variety of approaches to enhancing damage prevention programs. The group found that a comprehensive damage prevention program includes not only education but also effective enforcement. Currently, the U.S. Department of Justice is responsible for enforcing federal infrastructure damage prevention statutes on parties conducting excavations. However, and most unfortunately, the Department has rarely exercised such authority.

Programs such as Virginia's show that nine key elements must be present and functioning for the damage prevention program to be effective. The DIMP group concluded that federal legislation would be necessary to encourage such programs in all states. This should include providing additional funding for the states, apart from funding already being provided under the matching grants or One-Call programs.

As quoted from the above-mentioned DIMP report, the nine elements a state program should have are as follows:

(1) Effective communication between operators and excavators -- Provide for appropriate participation by operators, excavators, and other stakeholders in the development and implementation of methods for establishing and maintaining effective communications between stakeholders from receipt of an excavation notification until successful completion of the excavation, as appropriate.

(2) Fostering support and partnership of stakeholders -- Have a process for fostering and ensuring the support and partnership of stakeholders including excavators, operators, locators, designers, and local government in all phases of the program.

(3) Operator's use of performance measures – Include a process for reviewing the adequacy of a pipeline operator's internal performance measures regarding persons performing locating services and quality assurance programs.

(4) Partnership in employee training – Provide for appropriate participation by operators, excavators, and other stakeholders in the development and implementation of effective employee training programs. This would ensure that operators, the one-call center, the enforcing agency and the excavators have partnered to design and implement training for employees of operators, excavators and locators.

(5) Partnership in public education – Have a process for fostering and ensuring active participation by all stakeholders in public education for damage prevention activities.

(6) Dispute resolution process – Feature a process for resolving disputes that defines the state authority's role as a partner and facilitator to resolve issues.

(7) Fair and consistent enforcement of the law -- Provide for the enforcement of its damage prevention laws and regulations for all aspects of the excavation process including public education. The enforcement program must include the use of civil penalties for violations found by the appropriate state authority.

(8) Use of technology to improve all parts of the process – Include a process for fostering and promoting the use, by all appropriate stakeholders, of improving technologies that may enhance communications, locate capability, and performance tracking.

(9) Analysis of data to continually evaluate/improve program effectiveness – Contain a process for review and analysis of the effectiveness of each program element, and for implementing improvements identified by such program reviews.

AGA and APGA recommend that Congress enact legislation that modifies Title 49 USC Subtitle VIII, Chapter 601, *§ 60105 - State pipeline safety program certifications*, to insert a new section outlining the nine elements and providing for additional funding for implementation of the program. Such funding should be allocated directly to the State agency having oversight over pipeline safety. In addition to our own members as excavators, a variety of stakeholders will be affected by the proposed legislation, including in most states, entities presently not under the jurisdiction of state pipeline safety authorities. Accordingly, funding authority for the program should be sought from general revenues.

Past experience has shown that, without legislation, PHMSA's activities under its existing authority have had a limited effect, principally because many of the entities causing excavation damage were outside the agency's jurisdiction. Moreover, without associated funding, a legislative mandate for an enhanced program -- be it at the federal level or at the state level -- would be equivalent to an unfunded mandate and have minimal effect on existing state programs.

Finally, AGA and APGA support providing continued funding authority for grants to states to support One-Call programs and for partial funding of the Common Ground Alliance (CGA) damage prevention organization. The CGA has been instrumental in bringing to the forefront the need for excavation damage prevention as a shared responsibility among all locators, One-Call system operators, excavators and owners or operators of buried infrastructure facilities. Development and adoption of consensus-based best practices, education, and damage data collection are significant and worthwhile efforts under CGA sponsorship and should be continued.

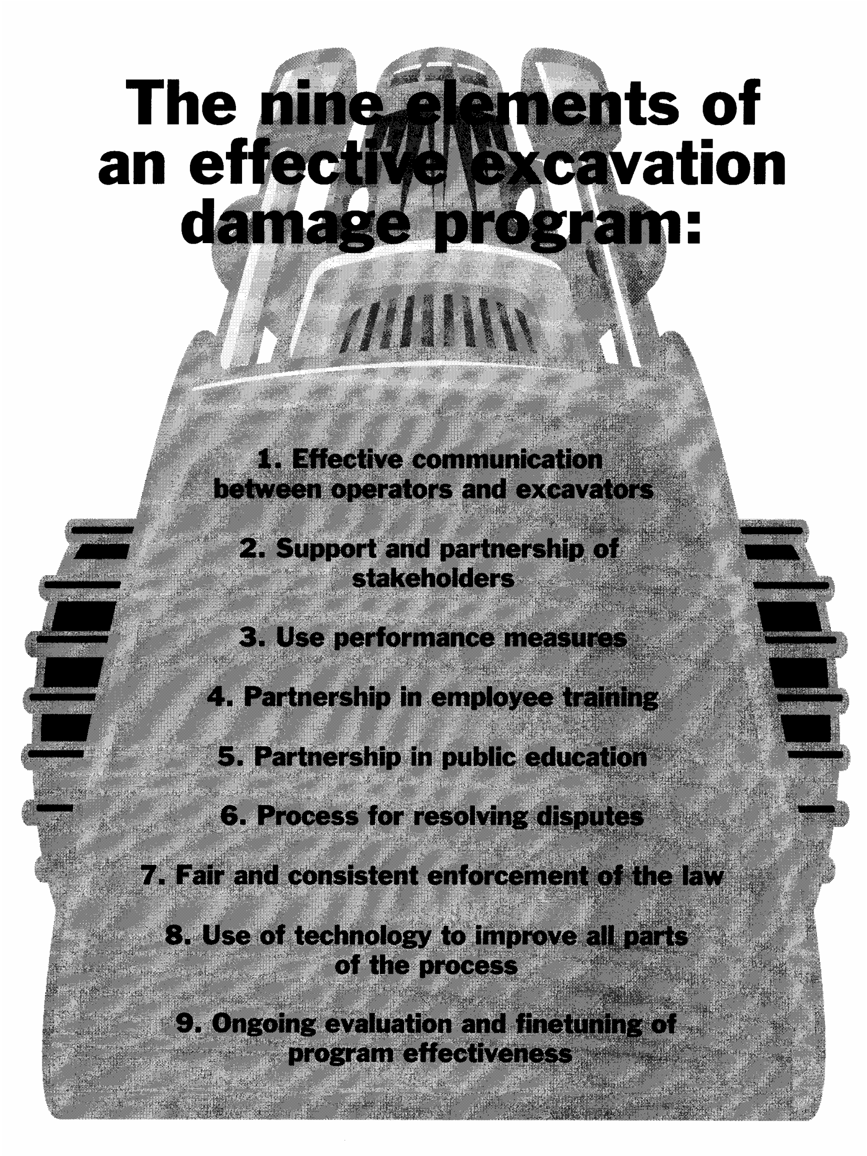
The statistics are clear. Excavation damage prevention presents the single greatest opportunity for distribution safety enhancements.

Gas Transmission Integrity Reassessment Time Interval

The Interstate Natural Gas Association of America testimony today addresses the 7-year reassessment interval required by the gas transmission integrity rule. In particular, gas company planning personnel view the overlap between the baseline assessments and the reassessments that must take place for a pipeline segment in year 7 after the baseline assessment as representing an unwarranted increase in workload and demand for services, with possible gas supply interruptions. This will affect interstate as well as intrastate transmission systems. AGA and APGA believe that a pipeline segment's reassessment interval should be based on technical arguments. It is our hope that in evaluating the appropriateness of the 7-year requirement, the U.S. Government Accountability Office (GAO) will seek to uncover all of the facts and that, based on the GAO report, Congress would then consider options for allowing a change to the interval that would be consistent with GAO findings. This will allow operators to continue to deliver natural gas safely and affordably.

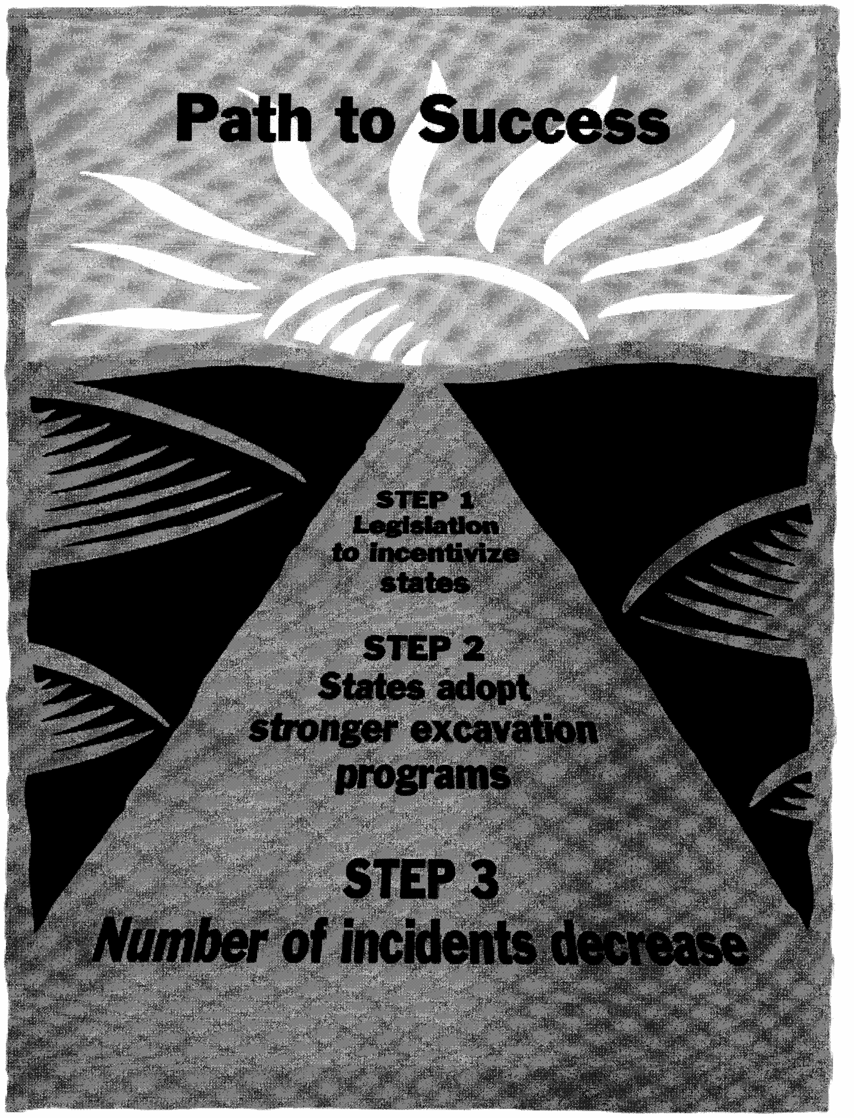
Attachments:

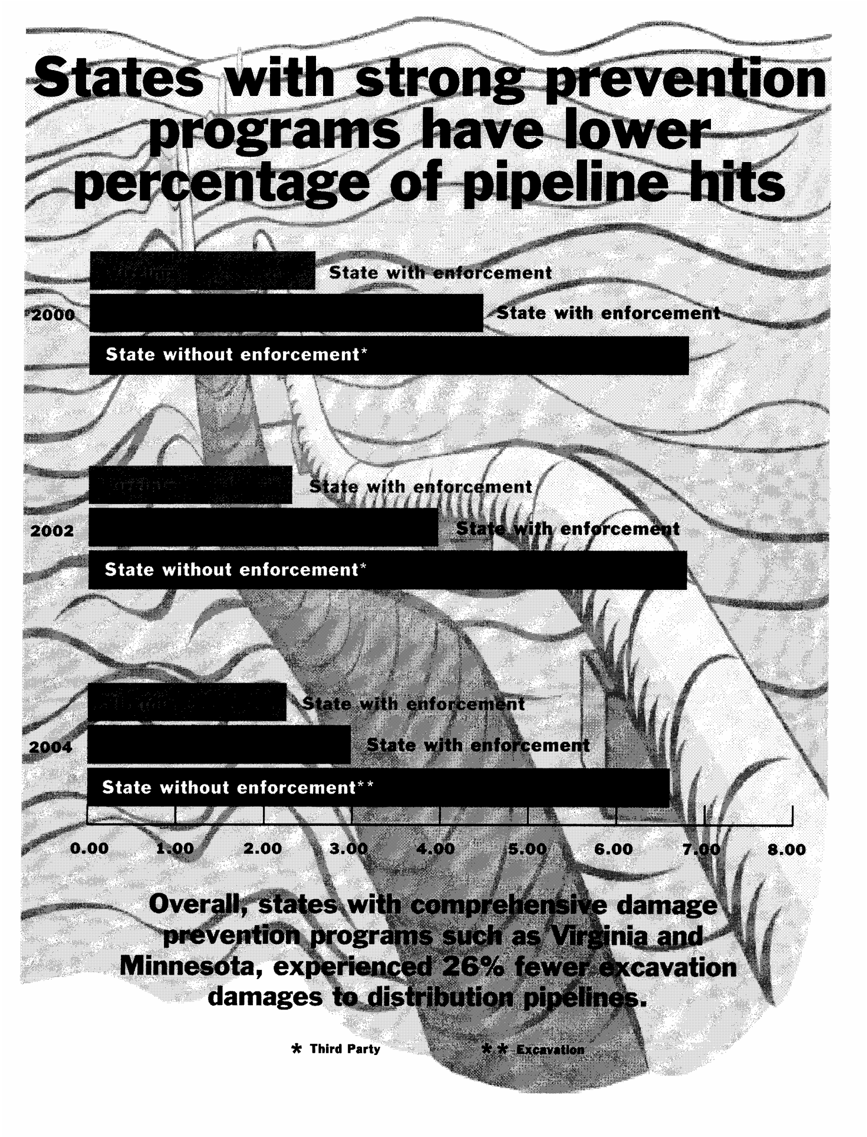
1) Comparison of Incidents
2) States With Strong Prevention Programs
3) The Nine Elements of an Effective Excavation Damage Program
4) Path To Success



The nine elements of an effective excavation damage program:

1. Effective communication between operators and excavators
2. Support and partnership of stakeholders
3. Use performance measures
4. Partnership in employee training
5. Partnership in public education
6. Process for resolving disputes
7. Fair and consistent enforcement of the law
8. Use of technology to improve all parts of the process
9. Ongoing evaluation and finetuning of program effectiveness


Path to Success
STEP 1
Legislation
to incentivize
states
STEP 2
States adopt
stronger excavation
programs
STEP 3
Number of incidents decrease



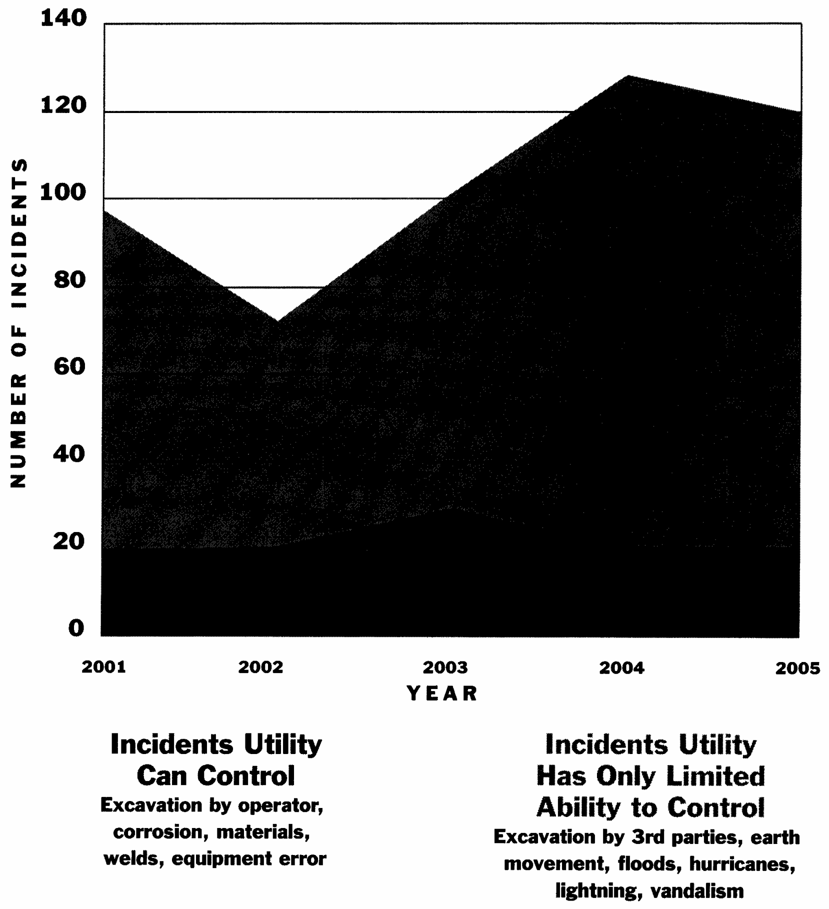
States with strong prevention programs have lower percentage of pipeline hits

Overall, states with comprehensive damage prevention programs such as Virginia and Minnesota, experienced 26% fewer excavation damages to distribution pipelines.

* Third Party

** Excavation

Comparison of Incidents Operators Can Control/Have Limited Ability to Control



MR. HALL. I thank you.

The Chair recognizes the Senior Vice President of Operations and Engineering for the Panhandle Energy, Mr. Mohn. And try to keep your remarks within about 5 minutes, if you can. Thank you.

MR. MOHN. I will do it, Mr. Chairman.

Good afternoon. My name is Jeryl Mohn. I am testifying today on behalf of the Interstate Natural Gas Association of America, or INGAA. Our trade association represents virtually all of the major gas pipelines in

North America. My testimony today will highlight some successes in the safety of gas pipelines and also suggest further improvements.

When Congress passed the Pipeline Safety Improvement Act in 2002, you set in motion one of the most significant regulatory improvement processes for pipeline safety since the original safety act of 1968, namely integrity management that you have heard a lot about today.

In short, the 2002 Act requires that we assess and remediate defects in high-consequence areas. The act requires the 10-year baseline inspection, as noted previously, and requires a 7-year reassessment of all pipelines in high-consequence areas. PHMSA formalized their final regulations in 2003, and we have made considerable progress in implementing integrity management. Through 2005, we completed assessment on about 30 percent of our HCAs, and we are on track to complete all of the baseline by 2012, including the highest priority 50 percent by the end of 2007. We are identifying defects and removing those from our pipelines before they become incidents. PHMSA began their audits last year, they are continuing this year, and we think they will validate the results that I have just commented on.

Next, I would like to give you a couple of thoughts on the matter before you, namely reauthorization.

We believe the existing law is effective and that only minor changes would further enhance pipeline safety. We do believe that it is in the best interest of all parties to complete the authorization in 2006 for something in the range of a 5-year period.

There are a couple of issues, however, I would like to mention, for your consideration. All of these are described further in my written testimony.

The first is something that you have heard quite a bit about before, namely the baseline overlap period. As we have heard before, the law requires that we establish a baseline condition of our pipelines within 10 years, something that we will complete by 2012, assessing about 10 percent of our pipelines a year. And then the law requires that once we have established that baseline, we begin to reassess on a 7-year frequency. The result, as you have heard, is that we will be required to double our efforts in the years 2010, 2011, and 2012.

While this interpretation of the law is understandable, we are not certain that that was the intent of Congress in 2002. We are further concerned that this doubling of the reassessment will have an impact on inspection resources. For inspection companies to suggest that they would ramp up for 3 years and double the amount of inspection services available and then go back down to that level in subsequent years is aggressive, from my perspective. Secondly, as you heard from your

GAO witness earlier, we are concerned that we may disrupt supply to our customers by doubling the inspection efforts during that 3-year period, and we urge you to consider fixing that overlap issue.

The second point is about the 7-year reassessment interval that I would like to make is really quite simple. As we know, GAO is examining the pluses and minuses, and I respect the need to await those results before you would make a firm judgment as to any change in that. I would offer you, though, just one observation, and that is this: reinspection is not new to our industry. At least two of our members began major assessments of their pipeline systems in the 1980s. One of those operators, who has over 8,100 miles of pipeline, has reassessed at least 80 percent of its pipeline twice during that period of time. Some of it they have reassessed at a more frequent basis, and others they have assessed on a less frequent basis, but on average, they are about 12 to 14 years between the reassessment. Again, I appreciate and we respect the need to await GAO's results, and we have tried to provide and will continue to work with GAO so that they have the benefit of that experience.

My last, and very important, recommendation is one that you have heard a lot about today, but it is an important element for high-pressure natural gas pipelines, and that is prevention of third-party damage. It is our leading cause of recent fatalities on our system, and we have, as an industry, been making continuous improvement for the last several years, as you have heard, and we would urge Congress to take a major step to help us crush those incidents going forward. You have just heard from my colleague from AGA as to the proposal that they would have, and we would urge you to consider those seriously.

To summarize quickly, from our perspective, the law is working, and we urge reauthorization in 2006 with only minor enhancements.

Thank you.

[The prepared statement of Jeryl L. Mohn follows:]

PREPARED STATEMENT OF JERYL L. MOHN, SENIOR VICE PRESIDENT, OPERATIONS AND ENGINEERING, PANHANDLE ENERGY, ON BEHALF OF INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

Summary of Testimony

INGAA appreciates the opportunity to testify on reauthorization of the Pipeline Safety Act. We want to provide the Subcommittee with some background on the natural gas pipeline industry and discuss the progress being made with the Integrity Management Program that was a part of the 2002 reauthorization. In general, INGAA believes the Integrity Management Program is working well in meeting the intent of Congress to reduce risks to the public. Our recommendations for legislation to reauthorize the Act in 2006 include:

- Five-year reauthorization.
- Re-examination of the seven-year reassessment interval that was part of the gas integrity management requirement in the 2002 legislation. We recommend a reassessment interval based on scientific and/or engineering criteria. At a minimum, the baseline assessment/reassessment overlap in years 2010 through 2012 should be eliminated.
- Incentives to further improve state damage prevention programs nationwide.
- Amend the definition of “direct sales lateral” pipelines in the Pipeline Safety Act to make those owned by interstate pipelines jurisdictional to federal, rather than state, oversight.

Mr. Chairman and Members of the Subcommittee:

Good morning. My name is Jeryl Mohn, and I am Senior Vice President of Operations and Engineering for Panhandle Energy. I am testifying today on behalf of the Interstate Natural Gas Association of America (INGAA). INGAA represents the interstate and interprovencial natural gas pipeline industry in North America. INGAA’s members transport over 90 percent of the natural gas consumed in the United States through a network of approximately 200,000 miles of transmission pipeline. These transmission pipelines are analogous to the interstate highway system – in other words, large capacity systems spanning multiple states or regions.

Panhandle Energy, headquartered in Houston, Texas, is a subsidiary of the Southern Union Company and owns or holds a major ownership interest in five interstate pipelines and a liquefied natural gas import terminal. Our pipelines serve a significant share of the markets in the Midwest, the Southwest including California, and Florida. In addition, our Trunkline LNG terminal in Lake Charles, Louisiana is one of the nation’s largest LNG import facilities.

INDUSTRY BACKGROUND

Mr. Chairman, natural gas provides 25 percent of the energy consumed in the U.S. annually, second only to petroleum and exceeding that of coal or nuclear. From home heating and cooking, to industrial processes, to power generation, natural gas is a versatile and strategically important energy resource.

As a result of the regulatory restructuring of the industry during the 1980s and early 1990s, interstate natural gas pipelines no longer buy or sell natural gas. Interstate pipelines do not take title to the natural gas moving through our pipelines. Instead, pipeline companies sell transportation capacity in much the same way as a railroad, airline or trucking company.

Because the natural gas pipeline network is essentially a “just-in-time” delivery system, with limited storage capacity, customers large and small depend on reliable around-the-clock service. That is an important reason why the safe and reliable operation of our pipeline systems is so important. The natural gas transmission pipelines operated by INGAA’s members and by others historically have been the safest mode of transportation in the United States. The interstate pipeline industry, working cooperatively with the Pipeline and Hazardous Materials Safety Administration (PHMSA), is taking affirmative steps to make this valuable infrastructure even safer.

Congressional involvement in pipeline safety dates back almost 40 years to enactment of the Natural Gas Pipeline Safety Act in 1968. This legislation borrowed heavily from the engineering standards that had been developed over the previous decades. The goals of this federal legislation were to ensure the consistent use of best practices for pipeline safety practices across the entire industry, to encourage continual improvement in safety procedures and to verify compliance. While subsequent reauthorization bills have improved upon the original, the core objectives of the federal pipeline safety law have remained a constant.

HOW SAFE ARE NATURAL GAS PIPELINES

While the safety record of natural gas transmission lines is not perfect, it nonetheless compares very well to other modes of transportation. Since natural gas pipelines are buried and isolated from the public, pipeline accidents involving fatalities and injuries are unusual.

In 2005 there were no fatalities and 5 injuries associated with our pipelines. During the period 2002 -2005, there were a total of two fatalities and 21 injuries. Both fatalities and nine of the injuries were attributable to excavation damage or vehicular crashes with pipeline facilities. The remainder of the injuries involved pipeline company repair/maintenance personnel.

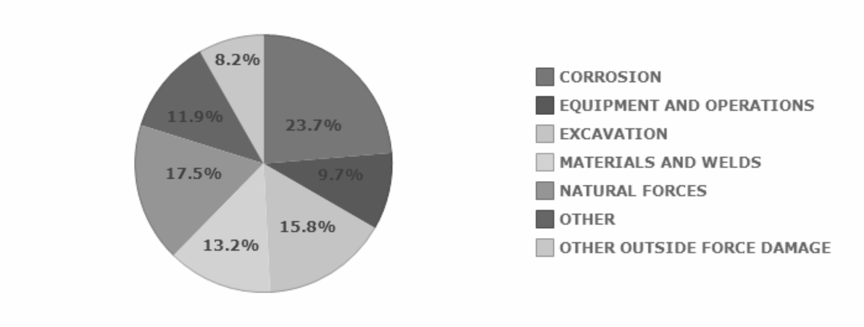
There are rare exceptions to the exceptional safety record of natural gas transmission pipelines. The accident that occurred near Carlsbad, New Mexico in 2000 resulted in the deaths of 12 family members who were camping on a remote pipeline right-of-way. That accident was the result of internal corrosion on a section of pipe that could not be inspected by internal inspection devices due to engineering constraints (more on that issue below). This has been the only gas transmission corrosion incident with fatalities since 1985, when PHMSA improved its record keeping system.

Since 1984, the Department of Transportation has defined a "reportable incident" as one that results in a fatality, an injury, or property damage exceeding $50,000. Included in the determination of property damage, however, is damage to the pipeline itself and the *monetary value of the natural gas lost*. As most of you know, natural gas commodity prices have increased more than 300 percent in the last six years. This linkage of "reportable incidents" to natural gas commodity prices has resulted in heavily skewed data over the last several years.

Internally, PHMSA has discussed a new "serious accident" incident category, which includes incidents with fatalities, injuries and fires. This category would rely less on the amount of natural gas lost to the air and would be, therefore, a more effective measure of safety performance. Another alternative would be a volumetric threshold for natural gas lost based on 2002 natural gas prices. If the 2005 incident data was normalized to 2002 gas prices, for example, 60 fewer onshore incidents would have been reported. Either approach would provide more consistency in the reportable incident data and help focus industry and PHMSA efforts on the more serious issues of human safety.

In terms of the causes of accidents on gas transmission pipelines, the table below shows that corrosion (internal and external) accounts for about one quarter of all incidents. This statistic is important, because the periodic inspection aspects of the Integrity Management Program discussed later are principally designed to reduce the risk of corrosion-related failures in highly populated areas. "Natural forces" was the second leading cause of damage, with the Gulf Hurricanes Ivan, Katrina and Rita accounting for most of these incidents. "Excavation damage," which tends to be the leading cause of fatalities associated with natural gas transmission lines, is the third leading cause of incidents. The new PHMSA accident statistics separate excavation damage from "other outside force damage" – most of the incidents associated with this new category are the result of vehicular crashes with pipeline facilities.

Natural Gas Transmission Failure Causes 2002-2005



Source: OPS FOIA Library Files March 08,2006

THE PIPELINE SAFETY IMPROVEMENT ACT OF 2002 AND INTEGRITY MANAGEMENT

The most recent reauthorization bill – the Pipeline Safety Improvement Act of 2002 ("PSIA") – focused on a variety of issues, including operator qualification programs, public education, and population encroachment on pipeline rights-of-way. But the most significant provision of the 2002 law that will improve long-term pipeline safety dealt with the "Integrity Management Program" ("IMP") for natural gas transmission pipelines.

Section 14 of the PSIA requires operators of natural gas transmission pipelines to: 1) identify all the segments of their pipelines located in "high consequence areas" (areas adjacent to significant population); 2) develop an integrity management program to reduce the risks to the public in these high consequence areas; 3) undertake baseline integrity assessments (inspections) at all pipeline segments located in high consequence areas, to be completed within 10 years of enactment; 4) develop a process for making repairs to any anomalies found as a result of these inspections; and 5) reassess these segments of pipeline every 7 years thereafter, in order to verify continued pipe integrity.

The PSIA requires that these integrity inspections be performed by one of the following methods: 1) an internal inspection device (or a "smart pig"); 2) hydrostatic pressure testing (filling the pipe up with water and pressurizing it well above operating pressures to verify a safety margin); 3) direct assessment (digging up and visually inspecting sections of pipe), or 4) "other alternative methods that the Secretary of Transportation determines would provide an equal or greater level of safety." The pipeline operator is then required by regulations implementing the 2002 law to repair all non-innocuous imperfections and adjust operation and maintenance practices to minimize "reportable incidents". For natural gas transmission pipelines, internal inspection devices are the primary means of integrity assessments, due to the fact that, when they can be used, they are more versatile and efficient. Other assessment alternatives listed in the legislation are useful in cases where smart pig technology cannot be effectively used. A drawback associated with such alternatives is that they require a pipeline to cease or significantly curtail gas delivery operations for periods of time.

In-line internal inspection "smart pig" devices were invented by the natural gas pipeline industry several decades ago, and over the years their capabilities and effectiveness as analytical tools have increased. Still, the pipeline industry must address some practical issues our industry must deal with in order to utilize these devices more fully.

First, our older pipelines were not engineered to accept such inspection devices. This means that older pipelines were often built with tight pipe bends, non-full pipe diameter valves, continuous sections of pipe with varying diameters, and side lateral piping. In all of these circumstances, the movement of natural gas is not impeded because of its relative compressibility. Moving a solid object through such pipelines is another matter, however. These older pipeline systems must be modified to allow the use of internal inspection devices.

The other legacy issue is the modification of pipelines to launch and receive internal inspection devices. Since a pipeline is buried underground for virtually its entire length, the installation of aboveground pig launchers and receivers is usually done at or near other above ground locations such as compressor stations. Occasionally, however, new sites must be obtained for these facilities. Compressor stations are typically located along the pipeline at a spacing of 75 to 100 miles apart. Therefore, for every segment, another set of launchers and receivers needs to be installed. Once installed, these launchers and receivers can usually remain in place permanently.

Surveys conducted by our industry about five years ago suggested that almost one-third of transmission pipeline mileage could immediately accommodate smart pigs, another one-quarter could accommodate smart pigs with the addition of permanent or temporary launching and receiving facilities, and the remainder, about 40-45 percent, would either require extensive modifications or never be able to accommodate smart pigs due to the physical or operational characteristics of the pipeline. Scheduling these extensive modifications to minimize consumer delivery impacts has been one of the most challenging aspects of the Integrity Management Program.

The natural gas pipeline industry will use hydrostatic pressure testing and direct assessment for segments of transmission pipeline that cannot be modified to accommodate smart pigs, or in other special circumstances. There are issues worth noting with both hydrostatic testing and direct assessment. In the case of hydrostatic testing, an entire section of pipeline must be taken out of service for an extended period of time, limiting the ability to deliver gas to downstream customers and potentially causing market disruptions as a result. In addition, hydrostatic testing – filling a pipeline up with water at great pressure to see if the pipe fails – is a destructive or “go – no go” testing method that must take into account pipeline characteristics so that it does not exacerbate some conditions while resolving others. Also, because of this “go – no go” nature, testing must continue until the segment successfully completes the test, generally 8 hours at pressure, with no leaks or failures.

Direct assessment is generally defined as an inspection method whereby statistically chosen sections of pipe are excavated and visually inspected at certain distance intervals along the pipeline right-of-way based on sophisticated above ground electrical survey measurements that predict problem areas. The amount of excavation and subsequent disturbance of landowner’s property involved with this technology is significant and does not decrease with future reassessments. Disturbing other infrastructures, including roads and other utilities, is also a significant risk and inconvenience for the public.

One final note. While the pipeline modifications and inspection activity can generally follow a pre-arranged schedule, repair work is an unpredictable factor. A pipeline operator does not know, ahead of time, how many anomalies an inspection will find, how severe such anomalies will be, and how quickly they will need to be repaired. Only the completed inspection data can provide that information. Repair work often requires systems to be shut down, even if the original inspection work did not affect system operations. The unpredictable nature of repair work must be kept in mind, especially during the baseline inspection period, when we can expect the number of required repairs to be the greatest.

INTEGRITY MANAGEMENT PROGRESS TO DATE

The integrity management program mandated by the PSIA is performing very well. The program is doing what Congress intended; that is, verifying the safety of gas transmission pipelines located in populated areas and identifying and removing potential problems before they occur. Based on two years of data, the trend is that our pipelines are safe and are becoming safer.

PHMSA immediately initiated a rulemaking to implement the gas integrity requirements upon enactment of PSIA in December of 2002. The Administration successfully met the one-year deadline set by the law for issuing a final IMP rule. Therefore, 2004 was the first full year of what will end up being a nine-year baseline testing period (the statute mandates that baseline tests on all pipeline segments in high consequence areas must be completed by December of 2012). PHMSA's final rule credits pipeline companies for some integrity assessments completed before the rule took effect, thereby mitigating the effects of the shorter baseline period.

PHMSA has reported on progress achieved thus far:

1. Total Gas Transmission Mileage in the United States – There are 295,665 miles of gas transmission pipeline in the U.S. INGAA's members own approximately 200,000 miles of this total, with the remainder being owned by *intra*state transmission systems or local distribution companies.
2. Total High Consequence Area (HCA) Mileage – There are 20,191 miles of pipeline in HCAs (i.e., mileage subject to gas integrity rule). This represents about 7 percent of total mileage.
3. HCA Pipeline Miles Inspected to Date –
    - 2004 – 3,979 miles (incorporated some prior inspections before rule took effect).
    - 2005 – 2,744 miles
    - Therefore, 6,723 miles of HCA pipeline inspected to date, or 33 percent of total.
4. Total Pipeline Miles Inspected (including non-HCA pipeline) –
    - 2004 – 30,452 miles (7.65 to 1 over-test ratio)
    - 2005 – 19,884 miles (7.24 to 1 over-test ratio)
    - Therefore, 50,366 total miles, or approximately 17 percent of total transmission pipeline mileage.

The total HCA pipeline mileage inspected to date suggests that the industry is generally on track with respect to meeting the 10-year baseline requirement. With three years of the baseline period completed at the end of 2005, about 30 percent of the HCA mileage had been inspected. This translates into 10 percent being completed annually – exactly the volume of work needed in order to meet the baseline requirement.

The 2002 law also required a risk-based prioritization of these HCA assessments, so that the higher-ranking HCA pipeline segments would be scheduled for assessment within five years of enactment. This means that by December of 2007 we must have completed at least half of the total HCA assessments, by mileage, and that work contains the segments with the highest probability of failure. Again, we appear to be on track for meeting this requirement.

The mileage counted as being assessed in 2004 is higher than what we anticipate will be the average annual mileage going forward, because we were able to include some HCA segments that had been inspected in the few years immediately prior to the rule taking effect. As mentioned, this helped to jump-start the program and make up for the fact that the final IMP rule did not take effect until December of 2003, thus reducing the *de facto* baseline period to nine years.

The vast majority of the assessments to date have been completed using smart pig devices. As discussed, these devices can only operate across large segments of pipeline – typically between two compressor stations. A 100 mile segment of pipeline may, for example, only contain 5 miles of HCA, but in order to assess that 5 miles of HCA, the entire 100 mile segment between compressor stations must be assessed. This dynamic is resulting in a large amount of "over-testing" on our systems. While we have completed assessments on 6,723 miles of HCA pipe thus far, the industry has actually inspected about 50,366 miles of pipe in order to capture the HCA segments. Any problems that are identified as a result of inspections, whether in an HCA or not, are repaired.

As you can see from the data, only about 7 percent of total gas transmission pipeline mileage is located in HCAs. Yet, due to the over-testing situation, we anticipate that about 55 to 60 percent of total transmission mileage will actually be inspected during the baseline period.

Now let us look at what the integrity inspections have found to date. For this data, we focus on information from HCA segments, since these segments are the only ones specifically covered under the integrity management program.

1. Reportable Incidents in HCAs (in 20,191 miles)
    - 2004 – 9 (2 time-dependent)
    - 2005 – 10 (0 time-dependent)
2. Leaks (too small to be classified as a reportable incident) in HCAs (in 20,191 miles)
    - 2004 – 117 (29 time-dependent)
    - 2005 – 104 (20 time-dependent)
3. Immediate Repairs in HCAs Found by Inspections (repair within 5 days)
    - 2004 – 101 (3,979 miles inspected)
    - 2005 – 237 (2,744 miles inspected)
4. Scheduled Repairs in HCAs Found by Inspections (repair generally within 1 year)
    - 2004 – 595 (3,979 miles inspected)
    - 2005 – 403 (2,744 miles inspected)

In the data for incidents and leaks, we separate out the time-dependent defects, since these are the types of defects that are the prime target of reassessment under the integrity management program. By time-dependent, we mean problems with the pipeline that develop and grow over time, and, therefore, should be examined on a periodic time basis. The most prevalent time-dependent defect is corrosion; therefore, the IMP effort is focused most intently on corrosion identification and mitigation. These same assessments might also be able to identify other pipeline defects such as original construction defects or excavation damage. Original construction defects are usually found and addressed during post-construction inspections; any construction defects found with this new, more sensitive inspection technology would be fixed "for good" so that future assessments looking for these types of anomalies will be unnecessary. Most reportable incidents caused by excavation damage (more than 85 percent) result in an immediate pipeline failure, so periodic assessments are not likely to reduce the number of these types of accidents in any significant way. Periodic assessments on a fixed schedule are, therefore, most effective for time-dependent defects.

You can see that the number of incidents associated with time-dependent defects in HCA areas is fairly low and that these reportable incidents (e.g. 1 reportable incident per year average) have occurred in HCA areas not yet assessed under this program. As critical time dependent defects are found and repaired, we expect these incident and leak numbers to approach zero, since the gestation period for these defects is significantly longer than the re-assessment interval.

As for repairs, we have identified the number of "immediate" and "scheduled" repairs that have been generated by the IMP inspections thus far. These are anomalies in pipelines that have not resulted in a reportable incident or leak, but are repaired as a precautionary measure. "Immediate repairs" and "scheduled repairs" are defined terms under both PHMSA regulations and engineering standards. As the name suggests, immediate repairs require immediate action by the operator, due to the higher probability of a reportable incident or leak in the future. Scheduled repair situations are those that require repair within a longer time period because of their lower probability of failure.

Even though we are early in the baseline assessment period, the data suggests a very positive conclusion regarding present state of the gas transmission pipeline system and the effectiveness of integrity management programs. "Immediate repairs" in HCAs removed 50 anomalies for every 1000 pipeline miles inspected. The number of "scheduled repairs" removed an additional 140 anomalies per 1000 miles inspected. By completing these immediate and scheduled repairs in a timely fashion, we are reducing the possibility of future reportable incidents or leaks. Also, data from operators who have completed more than one such periodic assessment over a number of years strongly suggests a dramatic decrease in the occurrence of time-dependent defects requiring repairs the second time around.

Many of the gas pipelines being inspected under this program are 50 to 60 years old. While is it often hard for non-engineers to accept, well-maintained pipelines can operate safely for many decades. Policymakers often compare pipelines to vehicles and ask questions such as: "Would you fly in a 50-year-old airplane?" The comparison to aircraft or automobiles is an unsound one, though, from an engineering standpoint. Natural gas pipelines are built to be robust and are not subject to the same operational stresses as vehicles. Much of the above inspection data comes from pipelines that were built in the 1940s and 1950s. And yet, the number of anomalies found on a per-mile basis is low. Once these anomalies are repaired, the "clock can be reset," and these pipelines can operate safely and reliably for many additional decades. One important benefit of the integrity management program is the verification and re-certification of the safety on these older pipeline systems.

ISSUES FOR THE 2006 REAUTHORIZATION

The 2002 Act authorized the federal pipeline safety program at the Department of Transportation through fiscal year 2006. Although the Congressional schedule for the rest of 2006 is short, the current program is working very effectively and therefore needs only modest changes. We therefore see no reason why Congress cannot reach consensus and complete a reauthorization bill this year. INGAA also urges the Congress to pass a five-year reauthorization bill that would take the next reauthorization outside the short legislative calendar that occurs in an election year.

INGAA would like the Subcommittee to consider amendments addressing three issues in the pipeline safety law. Each of these would achieve an evolutionary change in the current pipeline safety program: 1) re-consideration of the seven-year reassessment interval, to one based instead upon a more reasoned approach; 2) improvements in state excavation damage prevention programs; and 3) change in the jurisdictional status for direct sales lateral lines.

Seven-Year Reassessment Interval

Under the PSIA, gas transmission pipeline operators have 10 years in which to conduct baseline integrity assessments on all pipeline segments located in high consequence areas (HCAs). Operators are also required by law to begin reassessing previously-inspected pipe seven years after the initial baseline and every seven years thereafter. PHMSA has interpreted these two requirements to mean that, for those segments baseline-inspected in 2003 through 2005 (including those for which a prior assessment is relied upon), reassessments must be done in years 2010 through 2012 – *even though baseline inspections are still being conducted.*

In 2001 INGAA provided Congress with a proposed industry consensus standard on reassessment intervals that had been developed by the American Society of Mechanical Engineers (ASME). The ASME standard used several criteria to determine a reassessment interval for a particular segment of pipe, such as the operating pressure of a pipe relative to its strength and the type of inspection technique used. This standard relied upon authoritative technical analyses and a "decision matrix" based on more than 50 years of operational and performance data for gas pipelines.

For most natural gas transmission pipelines (operating at high pressures), the ASME standard proposed a conservative ten-year reassessment interval. The standard suggested longer inspection intervals for lower pressure lines, a small number of pipelines that are lower in risk due to their lower operating pressures. The standard also suggested shorter intervals for pipeline segments operating in higher-risk environments, including those where unusually aggressive corrosion would be more likely to occur. Recent and past pipeline inspection data confirms that the ASME criteria are conservative.

Why are we so concerned about the seven-year reassessment interval? First, there is the "overlap" in years 2010 through 2012. The ability to meet the required volume of inspections is daunting given the limited number of inspection contractors and equipment available. In addition, this stepped up level of inspection activity would be difficult to accommodate without affecting gas system deliverability. This last point is critical. Some assume that we are focusing on the re-assessment interval only because of the costs to industry. In fact, our costs will be modest compared to the potential costs to consumers in the form of higher natural gas commodity prices if pipeline capacity becomes too constrained. Some regions of the country can handle more frequent reductions in pipeline deliverability, due to the volume of pipeline capacity serving those regions. The Chicago region and the Gulf Coast, for example, are equipped to handle frequent pipeline capacity interruptions due to the abundance of pipeline capacity in those regions. Other regions, such as the Northeast and Southern California, face greater risk that gas commodity prices will spike if pipeline capacity is reduced too often. These downstream market effects should be carefully considered, especially during the baseline inspection period when pipeline modifications (to accommodate inspection equipment), inspections, and repair work will all be at peak levels.

Some also suggest that if the pipeline industry is technically capable of inspecting its lines for corrosion more frequently than engineering standards suggest, then it should do so and not worry about the costs or the logistics. It is certainly true that large interstate pipelines could, in fact, be inspected more frequently than every seven years, especially once systems have been modified to accommodate smart pig devices. But just because pipelines can be inspected more often does not mean it is rational to require a one-size-fits-all inspection policy. Most automobile manufacturers recommend vehicle oil changes every 3000 miles. Congress could instead mandate that all vehicles have oil changes every 1000 miles, but, of course, there would be little, if any, additional benefit to the more frequent oil changes, and the costs associated with the more frequent oil changes would take money away from other, more beneficial maintenance activities.

The Integrity Management Program asks us to identify and mitigate risks to the public associated with operating our pipelines. Inspections are but one tool to achieve that end, and they do not accomplish all of the required goals of the program. The inspections carried out pursuant to the Integrity Management Program focus primarily on one cause of pipeline accidents – corrosion. Corrosion causes about 25 percent of the failures on gas transmission lines. What about the other 75 percent of accidents? What can be done to mitigate the risks of those? A credible and effective integrity management program prioritizes risks and develops strategies for addressing all risks. A program that mandates system-wide inspections too frequently can seriously affect an operator's ability to perform even more frequent inspections at the very few locations that may warrant shorter timeframes and may detract from other important integrity activities such as damage prevention.

We recognize that some lawmakers may be hesitant to change to the seven-year reassessment interval given the heated debate on this issue in 2002. This is especially true given that the Integrity Management Program is relatively new and that GAO has not finalized its final report. We still urge the Congress to address the reassessment issue in this reauthorization bill, particularly the inspection overlap. The inspection overlap issue will manifest itself within the next four years; in other words, during the next reauthorization period. Our industry has worked in good faith to make the IMP program work and to improve pipeline safety overall. We want this safety initiative to work, but we also want to continue doing our collective job to deliver natural gas supplies reliably across the country when those supplies are needed. INGAA has provided the GAO with data that clearly shows there would be no compromise of safety either by lengthening the seven-year interval or by eliminating the baseline-reassessment overlap.

Damage Prevention

In 1998, the TEA21 highway legislation included a relatively modest program called the "One-Call Notification Act." The goal of this legislation was to improve the quality and effectiveness of state one-call (or "call-before-you-dig") damage prevention programs. By developing federal minimum standards and then giving grants to those states that adopted the minimum standards, this law contributed to improving damage prevention efforts all across the nation. And it did so without mandating that states adopt the federal minimum standards.

Over the last eight years, there has been a great deal of improvement in damage prevention. INGAA believes that the time has come to take these efforts to the next level. Excavation damage prevention has been, and should remain, a major focus for pipeline safety. On our gas transmission pipelines, accidental damage from excavation equipment is the leading cause of fatalities and injuries. The majority of incidents that have raised public and Congressional concern have been due to excavation damage. These accidents are the most preventable of all, and better communication between pipeline companies and excavators is the key to such accident prevention. Despite all the progress that has been made since 1998, some excavators still do not call before they dig.

One state, in particular, has developed an outstanding damage prevention program based on improved communication, information management, and performance monitoring. That state is Virginia. Not only does Virginia require broad participation by all utilities and excavators, but also it has effective public education programs and effective enforcement of its rules. We believe that enforcement is the most important element to improving state programs beyond the progress already made, and we believe Virginia offers a model for other states to adopt. Statistics demonstrate the success of the Virginia program – the state has experienced a 50 percent decrease in the excavation damage since implementing its program.

For 2006 we ask the Congress to emphasize once again the importance of excavation damage prevention by including a new program of incentives for state action. A modest amount of grant funds could go a long way in reducing accidents. INGAA would like to work with the American Gas Association and the Common Ground Alliance in proposing legislative language on this issue in the next few weeks.

Safety Regulation of Direct Sales Laterals

One of the goals of the original Pipeline Safety Act enacted in 1968 was to establish a clear line of demarcation between federal and state authority to enforce pipeline safety regulations. Prior to 1968, many states had established their own safety requirements for interstate natural gas pipelines, and there was no particular consistency in such regulations across the states. This created compliance problems for interstate pipeline operators whose facilities crossed multiple states. The Pipeline Safety Act resolved this conflict by investing the U.S. Department of Transportation with exclusive jurisdiction over interstate pipeline safety while delegating to the states authority to regulate intrastate pipeline systems (generally, pipelines whose facilities are wholly within a single state).

The statutory definition of an "interstate gas pipeline facility" subject to federal regulation was clarified further when the Congress reauthorized the Pipeline Safety Act in 1976 (P.L. 94-477). As part of this clarification, the Congress stated that "direct sales" lateral pipelines were not subject to federal jurisdiction. Direct sales laterals are typically smaller-diameter pipelines that connect a large-diameter interstate transmission pipeline to a single, large end-use customer, such as a power plant or a factory. Such direct sales laterals often are owned and maintained by the interstate transmission pipeline operator to which they are connected.

This clarification was made necessary by a 1972 U.S. Supreme Court decision (*Federal Power Commission v. Louisiana Power and Light, 406 U.S. 621*) in which the Court ruled that for purposes of economic regulation (*i.e.*, rate regulation), direct sales laterals were subject to preemptive federal jurisdiction. This ruling created uncertainty regarding the authority to regulate the safety of direct sales laterals because when the Pipeline Safety Act was enacted in 1968, it was assumed by the Congress that such pipelines would be subject to both economic and safety regulation at the state level.

While this exemption from federal jurisdiction may have made sense 30 years ago, it now is an anachronism. As mentioned, many of these direct sales laterals are owned and operated by interstate pipelines. The natural gas transported in such lines travels in interstate commerce, and the lateral lines are extensions of the interstate pipelines to which they are interconnected.

In addition, interstate natural gas pipelines are now subject to the PHMSA's Gas Integrity Management Program and are required to undergo a specific regimen of Congressionally mandated inspections and safety verification. State-regulated pipelines are not covered under the federal program. Instead, states are allowed to create their own safety programs, which may have different processes/procedures covered than the federal integrity management program. Given the comprehensive federal program, there is no particular reason for small segments of the interstate pipeline system to be subject to differing and potentially inconsistent regulation at the state level. The inefficiency of this approach is further compounded by the fact that an interstate pipeline operator with direct sales laterals in multiple states likely will be subject to inconsistent regulation across the states. It is therefore understandable that interstate pipelines wish to have their direct sales laterals subject to the same federal integrity management requirements as mainline facilities. This would ensure a consistent and rational approach to integrity management system-wide, in contrast to being compelled to exclude parts of the pipeline network on the basis of an outdated set of definitions.

INGAA supports amending the definitions of "interstate gas pipeline facilities" and "intrastate gas pipeline facilities" in the Pipeline Safety Act to eliminate the jurisdictional distinction between direct sales laterals and other segments of an operator's interstate natural gas pipeline system. This would make such segments of pipeline subject to federal safety regulation consistent with the approach taken for the economic regulation of such pipeline facilities.

Direct sales laterals that are not owned by an interstate pipeline would still be regulated by states. This amendment also would have the benefit of permitting the states to concentrate their resources on developing and enforcing integrity management programs for their natural gas distribution lines.

CONCLUSION

Mr. Chairman, thank you once again for inviting me to participate in today's hearing. INGAA has made the reauthorization of the Pipeline Safety Act a top legislative priority for 2006, and we want to work with you and the Subcommittee to move a bill forward as soon as possible. Please let us know if you have any additional questions, or need additional information.

MR. HALL. Thank you. That is exactly 5 minutes. Good.

Next the President and CEO of Explorer Pipeline Company, Mr. Felt, we recognize you for 5 minutes.

MR. FELT. Thank you, Mr. Chairman.

MR. HALL. And let me say this before you start. Don't be dismayed by the empty chairs here. It is an unusual day, and they have just called an emergency meeting of most of the Republicans for some upcoming legislation. That is where they are, but your testimony is being taken down. It will go to every member of this committee and every Member of Congress, and it will be read by everybody. So you are not testifying just to two guys here. You have the main ones with me, the legislative aides that are in attendance here. So thank you. And your time is valuable, and you are very valuable people, and we look to you to give us guidance on how to write the legislation that you need and the things that you need and that the country needs. And I thank you again for your time, but I am a little embarrassed that you don't have more people to talk to, but you are really talking to the Congress.

MR. FELT. Thank you, sir.

Mr. Chairman and members of the subcommittee, my name is Tim Felt. I am President and CEO of Explorer Pipeline Company headquartered in Tulsa, Oklahoma. We operate 1,400 miles of petroleum products pipeline serving 16 States extending from the Gulf Coast throughout the midwestern United States.

I am part of the leadership of the pipeline segment of the API, a member of the Association of Oil Pipelines, and the oil pipeline industry's board member on the Common Ground Alliance.

I appreciate the opportunity to appear today on behalf of API and AOPL. Together, API and AOPL represent the vast majority of U.S. oil pipeline transportation companies.

Mr. Chairman, I will summarize my written testimony, which has been submitted for the record.

It has been over 3 years since the enactment of the Pipeline Safety Improvement Act of 2002. On behalf of our members, I wish to thank you for your leadership in passing a comprehensive and very important legislation.

As the subcommittee reviews the current state of pipeline safety and the progress that has been made since the 2002 Act, these are the main points I would like to emphasize.

The Pipeline Safety Improvement Act of 2002 is a success. Industry and DOT have cooperated to achieve significant improvement in pipeline safety, and this improvement is demonstrated by our industry's record. This record is reflected on the charts that accompany my testimony. The oil pipeline industry is making the investments that are required to fully comply with the law, and in many cases, to exceed its requirements. In the liquid industry, plants invest over $1 billion in pipeline safety improvements over the next 5 years.

Finally, it is very important that Congress reauthorize the DOT pipeline safety program in 2006 to send a clear signal that these investments are appropriate and the DOT is on the right track to implementing the 2002 Act. A 5-year reauthorization would provide that needed certainty.

About 40 percent of the total U.S. energy supply comes from petroleum, but the transportation sector depends on petroleum for 96 percent of its energy. Two-thirds of domestic crude oil and refined products transportation is provided by pipeline. Pipelines do this safely and efficiently. The cost to transport a gallon of petroleum by pipeline is very low, typically 2 to 3 cents per gallon.

Oil pipelines are common carriers whose rates are controlled by the Federal Energy Regulatory Commission. Oil pipeline income is driven only by the volume transported and does not depend on the price of the products transported. In fact, high oil prices have a negative impact on the oil pipeline income by raising power costs and reducing demand for petroleum.

Oil pipeline operators have been subject to DOT's pipeline integrity management regulations since March 2001, before enactment of the 2002 Act. Initially, DOT estimated approximately 22 percent of the pipeline segments in the national oil pipeline network would be assessed and provided enhanced protection. However, DOT's inspections of operators' plans show that integrity testing will eventually cover approximately 82 percent of the Nation's oil pipeline infrastructure, almost four times the original estimate.

Large oil pipeline operators, those with over 500 miles of pipeline, completed the required 50 percent of their baseline testing of the highest-risk segments prior to the September 30, 2004, deadline set by the regulations.

DOT has audited each of these operators under these regulations at least two times, an initial quick-hit audit and one subsequent full audit. Although operating under a different deadline, the same program has been followed by the smaller operators.

Operators are repairing conditions in need of repair and less serious conditions that are found in the course of investigating defects. Operators are fixing what they find, often going beyond the requirement of the law.

As a result of this program, the oil pipeline spill record has improved dramatically in the last 5 years, as the exhibits show. The data for these exhibits come from a voluntary industry program that, since 1999, has collected data on oil pipeline performance. These figures represent pipeline releases, which are those that occur outside a pipeline company's facilities and are the releases most likely to impact the public. For each cause category, the trend is down. The number of total releases has dropped 51 percent. Releases due to corrosion have dropped 67 percent. Releases due to operator error have dropped by 63 percent. Finally, releases from third-party damage from excavation have dropped 37 percent.

The safety improvement has been dramatic even though the data only covers half of the 7-year baseline assessment period for oil pipelines. We expect this trend to continue as we complete the full cycle and begin reassessment intervals. This provides a clear indication that the program is working, and we can make this good program even better. Releases caused by excavation damage are the largest, most traumatic, and the most likely to threaten the public and the environment.

We believe new legislation is appropriate to strengthen the underground damage prevention. Recently DOT has discussed strengthening Federal enforcement authority when excavating is undertaken without using the available one-call system. DOT has also discussed raising the ceiling on Federal funding for States whose damage prevention programs meet certain standards set forth in statute. We would support these changes in law to foster more effective underground damage prevention. Regulation of oil pipelines operating at low stress has received attention in the aftermath of a recent leak from a low-stress line on the north slope of Alaska.

While the pipeline industry is developing a proposal for low-stress pipelines that we will submit to DOT, we will support risk-based regulation of these low-stress pipelines that pose a significant threat to high-consequence areas. DOT can put such a program in place using existing elements in its successful integrity management regulations. Existing legislative authority is adequate to accomplish this.

Finally, you should be aware of the fine job that PHMSA did in assisting pipeline operators in the aftermath of the hurricanes in 2005. They are familiar with their operations and readily served as a resource in answering questions, securing permits, and advising us of important contacts and interim requirements. They also helped us locate temporary power-generating equipment, and served as a voice to others in the Government. This helped us restore service and therefore product was supplied to areas served by Gulf Coast refineries.

In summary, current pipeline safety law is working and working very well. Improvements can be made, particularly in strengthening underground damage prevention, but fundamental changes are not needed. Rather, consistency and predictability are important as oil pipeline operators claim continued investments for safety and reliability. We need Congress to act now to reaffirm the course set in 2002 by reauthorizing the program for 5 more years.

This concludes my remarks. I would be happy to answer questions.

[The prepared statement of Timothy C. Felt follows:]

PREPARED STATEMENT OF TIMOTHY C. FELT, PRESIDENT AND CEO, EXPLORER PIPELINE COMPANY, ON BEHALF OF ASSOCIATION OF OIL PIPE LINES

The objectives of this testimony are:

- The Pipe Line Safety Improvement Act of 2002 is a success. Industry and DO have cooperated to achieve significant improvement in pipeline safety, and this improvement is demonstrated by our industry's record.
- The oil pipeline industry is making the investments that are required to produce this improved performance. We are on track to spend over $1 billion on pipeline safety over the next five years.
- It is very important that Congress reauthorize the DOT pipeline safety program in 2006 to send a clear signal that these investments are appropriate and DOT is on the right track in implementing the 2002 Act.
- Improvements in DOT's authority to promote underground damage prevention are appropriate, but there is no urgent need for fundamental changes in the pipeline safety statures at this time. What is needed is vigorous implementation of the 2002 Act, and that is happening.

Improved Spill Record – Oil pipeline operators have been subject to the DOT's pipeline integrity management regulations since March 2001. As a result of this program, the oil pipeline spill record has improved dramatically in the last five yeas. The number of total releases has dropped 51 percent and each cause category is down. (See attached charts). We expect this trend to continue as we complete the remaining 50% of the required baseline inspections. This provides clear evidence the program is working.

Damage Prevention – Releases caused by excavation damage tend to be more traumatic, larger and more likely to threaten the public and the environment in comparison to other causes. We believe new legislation may be appropriate to strengthen underground damage prevention. We would support changes in law to encourage states to adopt more effective underground damage prevention programs like the ones in Virginia and Minnesota.

Low Stress Pipelines – Regulation of oil pipelines operating at low stress levels has received attention in the aftermath of BP's recent leak on the Alaska North Slope. The oil pipeline industry expects to make proposal to DOT to use existing law to bring low stress oil pipelines that could affect high consequence area into a proactive spill prevention program using elements of DOT's successful integrity management regulations. Existing legislative authority is adequate to accomplish this.

Introduction

I am Tim Felt, President and CEO of Explorer Pipeline. I am here to speak on behalf of AOPL and the pipeline members of API. I appreciate this opportunity to appear before the Subcommittee today on behalf of the AOPL and API.

AOPL is an unincorporated trade association representing 48 interstate common carrier oil pipeline companies. Our membership is predominately domestic, but we also represent oil pipeline companies affiliated with Canadian pipeline companies. AOPL members carry nearly 85% of the crude oil and refined petroleum products moved by pipeline in the United States. API represents over 400 companies involved in all aspects of the oil and natural gas industry, including exploration, production, transportation, refining and marketing. Together, these two organizations represent the vast majority of the U.S. pipeline transporters of petroleum products.

Explorer Pipeline operates a 1,400-mile pipeline system that transports gasoline, diesel fuel and jet fuel from the Gulf Coast to the Midwest. Explorer is based in Tulsa, Okla., and also serves Houston, Dallas, Fort Worth, St. Louis and Chicago. Through connections with other products pipelines, Explorer serves more than 70 major population centers in 16 states. Explorer currently transports refined products with more than 72 different product specifications for over 60 different shippers. The company does not buy or sell petroleum products; it only provides transportation services. Explorer is owned by subsidiaries of Chevron, Citgo, Conoco Phillips, Marathon, Sun, Texaco, and Shell.

Summary

It has been over three years since the enactment of the Pipeline Safety Improvement Act of 2002 (Public Law 107-355, the “PSIA”). On behalf of the members of AOPL and API, I wish to thank the Members of this Subcommittee for their leadership in passing that comprehensive and very important legislation.

As the Committee reviews the current state of pipeline safety and the progress that has been made since the PSIA 2002 became effective, there are a few points that we would like to emphasize.

- The PSIA, actions by DOT’s Pipeline and Hazardous Materials Safety Administration (PHMSA) and initiatives taken by industry on its own have combined to produce significant improvement in pipeline safety, and this improvement is demonstrated by the record.
- Substantial changes at DOT and in the industry are under way as a result of greater safety oversight and strengthening in safety requirements. Under the PSIA, industry and its regulators are driving towards even stronger safety programs that will result in further improvements in performance in the future.
- The oil pipeline industry is making the investments that are required to produce this improved performance. We are on track to spend over $ 1 billion on pipeline safety over the next five years.
- Since the hurricanes in 2005, a new awareness of the vital importance of a robust, reliable and secure pipeline system has developed in government, industry and the public.
- Improvements in DOT’s authority to promote underground damage prevention are appropriate, but there is no urgent need for fundamental changes in the pipeline safety statutes at this time. What is needed is vigorous implementation of the 2002 Act, and that is happening.
- It is important that Congress send a signal before adjournment in 2006 affirming the general direction of the PSIA by reauthorizing the pipeline safety program for at least 5 more years with increases in funding levels to match projected inflation.

The Role of Pipelines in Petroleum Supply

About 40 percent of total U.S. energy supply comes from petroleum, but transportation in the U.S. depends on petroleum for 96 percent of its energy. The nation's transportation system could not operate without petroleum. Fully two-thirds of the ton-miles of domestic petroleum transportation are provided by pipeline. The total amount delivered by both crude oil and refined petroleum products pipelines (13.4 billion barrels in 2004) is nearly twice the number of barrels of petroleum consumed annually in the United States.

The major alternatives to pipelines for delivery of petroleum are tank ship and barge, which require that the source and user be located adjacent to navigable water. Trucks and rail also carry petroleum, but are limited in very practical ways in the volume they can transport. In fact, pipelines are the only reasonable way to supply large quantities of petroleum to most of the nation's consuming regions. Pipelines do so efficiently and cost-effectively – typically at 2-3 cents per gallon for the pipeline transportation cost charged to deliver petroleum to any part of the United States.

Oil pipelines are common carriers whose rates are controlled by the Federal Energy Regulatory Commission. Pipelines only provide transportation, and our owners do not profit from the sale of the fuels they transport.

Oil pipeline income is not related to the price of the products that are transported. In fact, high oil prices can have negative impacts on oil pipelines by raising power costs and reducing the demand for petroleum.

Oil pipelines move 17% of interstate ton-miles at only 2% of the cost of interstate freight transportation, a bargain that American consumers have enjoyed for decades.

The oil pipeline infrastructure is crucial to American energy supply. The care and stewardship of this critical national asset is an appropriate public policy concern and an important joint responsibility of the industry I represent, the Department of Transportation and Congress.

Progress Report on Pipeline Safety Integrity Management

Companies represented by AOPL and API operate 85 percent of the nation's oil pipeline infrastructure. Since March 2001 (for large operators) and February 2002 (for small operators), oil pipelines have been subject to a mandatory federal pipeline safety integrity management rule (Title 49, section 195.452) administered by the DOT's Pipeline and Hazardous Material Safety Administration (PHMSA). The oil pipeline industry's experience with pipeline integrity management preceded the enactment of the PSIA. Our members who are large operators completed the required 50 percent of their baseline testing of the highest risk segments prior to the September 30, 2004 midpoint deadline set by the integrity management regulations. PHMSA has inspected the performance of each of these operators under these regulations at least twice – an initial "quick hit" inspection and a subsequent full inspection. Regular inspections are a permanent part of our future. Oil pipelines have experience with the PHMSA integrity management program that will be instructive to the Subcommittee in its review.

Improvement in spill record

The oil pipeline spill record has improved dramatically in the last five years as exhibit 1 and 2 show. The data for these exhibits comes from a voluntary industry program that since 1999 has collected data on oil pipeline performance. This program is the Pipeline Performance Tracking System sponsored by the American Petroleum Institute and the Association of Oil Pipe Lines. (For more on PPTS, see http://www.api.org/ppts). The PPTS spill database is more detailed than any other similar database in existence, including data maintained by PHMSA. Exhibit 1 shows PPTS data for line pipe releases for the 1999-2004 period. Line pipe releases are those that occur outside the company's facilities. They are the releases that have the most direct potential effect on the public and the environment. For each cause category, the trend is down. The number of total releases dropped 51 percent between 1999 and 2004. Releases due to corrosion dropped 67 percent. Releases due to third party damage dropped 37 percent. Releases due to operator error dropped 63 percent. During this period, the volume released in incidents on line pipe dropped 40 percent.

Pipeline inspection and repair

In 2000, OPS estimated that under its proposed pipeline integrity management program approximately 22 percent of the pipeline segments in the national oil pipeline network would be assessed and provided enhanced protection. In fact, when oil pipeline operators carried out their analyses of how many of their segments could affect high consequence areas under the terms of the regulation, it turned out that almost twice as many segments, 43 percent of the pipeline network nationally, were covered. But in fact, the actual benefits realized have been even larger. The predominant method of testing oil pipelines utilizes internal inspection devices. The ports at which these devices are inserted into and removed from a pipeline are in most instances fixed in the system. As the internal inspection devices travel between ports they generate information about all the pipeline segments between those ports, which can be 35 to 50 miles apart. As a result, as shown in OPS inspections of operators' plans, it is estimated that integrity testing will cover approximately 82 percent of the nations' oil pipeline infrastructure. Thus the actual pipeline mileage protected by the program as implemented will be almost four times the original OPS estimate.

Operators are finding and repairing conditions in need of repair and less serious conditions that are found in the course of investigating defects. Operators are fixing what they find, often going beyond the requirements of the law. The largest cost to the operator is in the scheduling and renting of the internal inspection device, obtaining the required permits to excavate the line and carrying out the excavation, so once the pipeline is uncovered, operators fix many conditions that might never have failed in the lifetime of the pipeline.

Cost

Although benefits from the integrity management rule are much greater than originally estimated, so is the cost. Costs per operator are often in the low tens of millions of dollars per year, far more than originally anticipated. We estimate that the cost of inspection and repair for the industry has averaged nearly $8,000 per mile. Operators have nevertheless moved aggressively to provide the resources needed to implement integrity management.

The pipeline cost benchmarking survey conducted by the oil pipeline industry provides a snapshot for 2004 of the cost of integrity management activities of 19 oil pipeline companies. These companies operated 71,000 miles of pipeline (approximately 42% of the U.S. total of 167,000 miles of oil pipelines under DOT jurisdiction), about half of which was identified as segments that could affect a high consequence area. The total cost of the integrity management programs of these 19 companies in 2004 was $215 million. These operators inspected some 27,500 miles of pipeline in 2004 using inline inspection or hydrostatic pressure testing (some segments are tested with more than one technique), at a total cost of $7,820 per mile.

PHMSA's performance

The members of AOPL and API supported the establishment of DOT's Pipeline and Hazardous Materials Safety Administration. Our members have seen positive results from elevating pipeline safety to the modal level within the DOT. In our view, PHMSA has been very aggressive in seeking to implement the provisions of the PSIA, has shown enhanced ability to work effectively with other federal agencies whose activities impact pipeline safety and has joined with the pipeline industry and interested stakeholders to achieve important results for pipeline safety and reliability.

Security

In addition, PHMSA has been playing a very important and positive role in assisting the pipeline industry and the Department of Homeland Security in developing a security program to protect critical pipeline infrastructure that complements the risk-based integrity management program that PHMSA administers under the Pipeline Safety Act. PHMSA's September 5, 2002 Pipeline Security Information Circular remains the principal federal guidance for pipeline industry security programs. The DHS's Transportation Security Administration has joined PHMSA in conducting inspections of pipeline facilities based on the provisions of this circular.

PHMSA currently has the mission of regulating security with respect to non-pipeline hazardous materials transportation in coordination with DHS. We believe Congress should consider assigning PHMSA a parallel role in the security of pipeline transportation. PHMSA has an experienced inspection force and by far the greatest expertise in pipeline operations of any of the federal agencies. Therefore, it makes sense to leverage those resources and expertise in developing an effective federal pipeline security program. PHMSA is familiar with the use of risk management and cost benefit techniques that are critical to developing security measures that work in the real world of limited resources.

Oil pipeline operators will continue to cooperate with PHMSA, TSA and DHS to meet the government's pipeline security expectations pending clarification by Congress of the federal agency oversight responsibilities for pipeline security.

Pipeline Personnel Qualification

The PSIA required pipeline operators to develop programs to qualify pipeline personnel for tasks performed on the pipeline. These programs must require training where appropriate and periodic reevaluation of the qualifications of all pipeline personnel. Pipeline operators have responded with comprehensive programs that provide added assurance that only qualified personnel work on our pipelines. An important recent development is a joint pipeline industry association letter to PHMSA recommending a modification to PHMSA's pipeline personnel qualification rules to indicate specifically when training of personnel may be appropriate and to provide for intervals for the periodic re-evaluation of the qualifications of individual personnel. Our letter is attached. Ensuring the ability of PHMSA to enforce appropriate training and evaluation requirements has been a long-standing interest of the National Transportation Safety Board. It is our understanding that PHMSA is considering modifications to its rules that will fully address the NTSB interest. The purpose of our letter is to indicate the joint industry's support for such a modification.

Areas for improvement in the federal pipeline safety program

The pipeline industry 's first priority is a clear Congressional reaffirmation -- before the 2006 adjournment -- of the direction charted by Congress for DOT and the industry in the Pipeline Safety Improvement Act of 2002. Accordingly, we urge that the Subcommittee at a minimum pass a bill in this Congressional Session that extends PHMSA funding authority for at least 5 years. If in addition Congress decides that improvements to the pipeline safety statutes are appropriate and can be enacted in this Session, we would be prepared to participate and put forward our own recommendations consistent with the thrust of the 2002 Act. If the opportunity to include substantive legislation arises, we would recommend consensus legislative provisions addressing excavation damage prevention, streamlining transmission pipeline integrity management and enhancing the efficiency and effectiveness of PHMSA. Below we discuss several areas where improvement in the federal pipeline safety program is warranted, although in many cases this improvement may be able to be achieved without new legislation.

Damage prevention

An area where new legislation may be appropriate is underground damage prevention. Damage to buried pipelines during excavation is a persistent, preventable and significant cause of pipeline releases. Releases caused by excavation damage tend to be more traumatic, larger and more likely to threaten the public and the environment in comparison to releases from other causes. Damage prevention programs are almost totally controlled by the laws of the several states, and the federal interest in promoting damage prevention must be expressed in partnership with the states in most instances.

Enforcement of damage prevention laws varies among the states across the entire spectrum of effectiveness. The affected interests in damage prevention are typically beyond the reach of any single regulatory authority, so often the most feasible approach is a cooperative one that brings affected interests together in a voluntary commitment to improvement. I am a board member of the Common Ground Alliance, an organization that Congress helped start that brings the key interests in damage prevention together to work cooperatively to improve safety. We understand that a promising approach to improving state damage prevention programs has recently been developed under the auspices of CGA and the Distribution Integrity Management Team. We would urge the Subcommittee to take this approach seriously and, if appropriate for purposes of reauthorization in 2006, include the necessary legislative provisions in your reauthorization bill.

Public Information, including the National Pipeline Mapping System

Prior to the terrorist attacks of September 11, 2001 PHMSA developed the National Pipeline Mapping System (NPMS). Pipeline maps and basic information about the pipeline were made available to public through the internet. After 9/11 access to information on the NPMS was restricted. The public could only obtain pipeline operator contact information within a specified geographic location and could no longer view the maps. PHMSA then developed the Pipeline Integrity Management Mapping Application (PIMMA) for use by pipeline operators and federal, state, and local government officials. The application contains sensitive pipeline critical infrastructure information. PIMMA is intended to be used solely by the person who is given access by PHMSA and is not available to the public.

PHMSA also requires pipeline operators to prepare annual reports of their operations, and these annual reports are available to the public upon request. Many pipeline companies also provide general information about their pipelines on their websites and as part of their public awareness programs. Much of the information in NPMS and other locations in PHMSA would help better inform the public and could be made available at some level that would not pose an undue security risk.

We believe it is time that PHMSA and the Transportation Security Administration re-establish public access to the NPMS and determine what non-sensitive information already submitted by pipeline operators to PHMSA may be made available to the public.

Pipeline Repair Permit Streamlining

An important initiative of the PSIA is section 16, “Coordination of Environmental Reviews”, which is concerned with expediting the repair of pipeline defects. While progress has been made on implementing this section, more work remains to be done, and the deadlines for agency action under the provision have passed. Since passage of the PSIA, the Council on Environmental Quality has played an important leadership role in implementing section 16. In June 2004, CEQ Chairman James Connaughton testified on before the Senate Committee on Commerce, Science and Transportation. He described an ambitious plan to coordinate pipeline repair information and decision-making among the federal agencies. We were very pleased at the time to hear Chairman Connaughton's plan for implementing section 16. It is unfortunate that that plan has not been carried out, despite its obvious merit under the terms of the PSIA. On December 15, 2005, the joint industry associations wrote to CEQ seeking action on an important provision of the Connaughton/CEQ plan: a pilot test for a set of pre-approved Best Management Practices (BMPs) for pipeline repair site access, use and restoration. A copy of the letter is attached. To date, our letter has not been answered.

Under the Connaughton/CEQ plan, a commitment by an operator to adhere in good faith to the BMPs would result in expedited permission to access repair sites to carry out the repair in order to allow repairs to be completed within the timeframes specified by DOT regulation. A multi-agency website would be used to coordinate response to requests for permits such that involved agencies operate in parallel or in concert to issue all required permissions to the operator in a timely fashion. To the extent possible the permitting process would be consolidated to limit to one the number of permits required (a consolidated permit) for each project. The process would also ensure that federal agencies are aware of the relationships in permitting pipeline repairs among federal, state and local requirements and can act accordingly to achieve the goal of section 16.

We may need assistance from the Subcommittee to achieve the goals of section 16 while complying with the Endangered Species Act. One way to accomplish this would be through an agreement between the Department of Transportation and the Department of the Interior under which DOT would voluntarily assume the role of default coordinator (or *nexus*) for pipeline repairs in those cases where no other federal agency is available or able to act as the federal nexus for ESA consultation. If legislation is judged to be necessary to facilitate such an agreement and role for DOT, we recommend that the Subcommittee seriously consider it.

Our industry is eager to help carry out the vision Chairman Connaughton has articulated. We urge the CEQ to assign appropriate staff resources to accelerate progress with the plan. Section 16 is Congress's direction to the executive branch agencies under CEQ's leadership to facilitate full compliance with applicable environmental laws in the conduct of pipeline repairs while at the same time meeting the time periods for completion of repairs specified in DOT regulations. We have no intention other than full compliance with the applicable environmental laws, and are eager to assist in any way possible to devise a process that will harmonize objectives of the pipeline safety statutes with compliance with those laws.

Encroachment

Section 11 of the PSIA required DOT to study land use practices, zoning ordinances and preservation of environmental resources in pipeline rights-of-way to determine effective practices to limit encroachment on these rights-of-way. DOT complied with section 11 by contracting with the Transportation Research Board of the National Academies to carry out the study. "Transmission Pipelines and Land Use, a Risk-Informed Approach", is available from the TRB website at http://www.nap.edu/catalog/11046.html.

The TRB study recommended that DOT convene a multi stakeholder process to develop practices to limit encroachment that could be recommended to state and local government, developers and landowners along pipelines. The TRB favorably noted experience with the Common Ground Alliance in addressing excavation damage issues as a possible model for addressing encroachment issues. The oil pipeline industry is ready to participate enthusiastically, and encouragement of the process from the Subcommittee would be welcomed.

Oil Pipelines Operated at Low Stress

Regulation of oil pipelines operating at low stress has received attention in the aftermath a recent leak from a low stress line on the North Slope of Alaska. The oil pipeline industry is developing a proposal for low stress pipelines that we will submit to DOT. We will support DOT in the regulation of those low stress pipelines that pose a significant threat to high consequence areas. We will recommend a risk-based program of proactive spill prevention for such lines that DOT can put in place using elements of the DOT's successful integrity management regulations. Existing legislative authority is adequate to accomplish this.

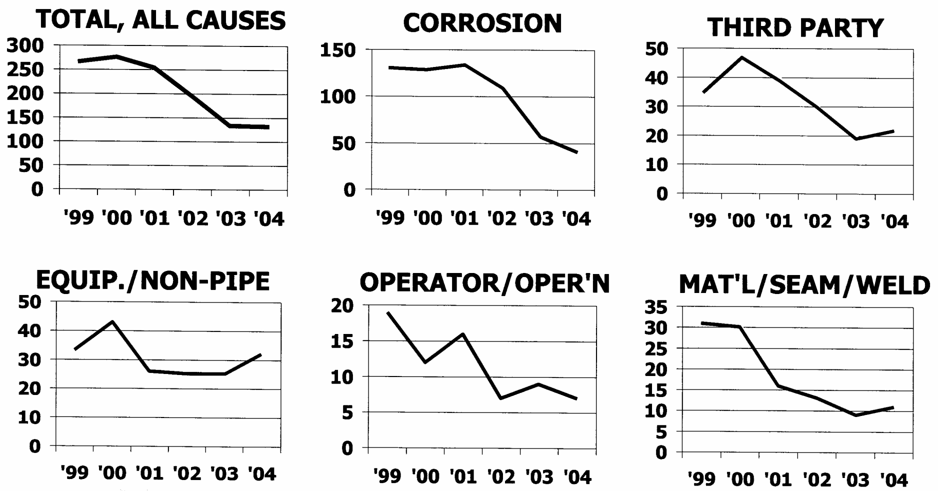
Conclusion

The PSIA 2002 continues to provide valuable guidance that has resulted in significant improvement in the safe operation of hazardous liquid and natural gas pipelines. AOPL and API urge this Subcommittee and Congress to pass legislation in 2006 that will provide DOT and the industry certainty in the years ahead by reaffirming the overall direction provided by the PSIA 2002 and extending its provisions for at least an additional 5 years.

Thank you for the opportunity to testify before the Subcommittee on these important matters.

Exhibit 1

Onshore Pipe Incidents, '99-'04



TOTAL, ALL CAUSES

CORROSION

THIRD PARTY

EQUIP./NON-PIPE

OPERATOR/OPER'N

MAT'L/SEAM/WELD

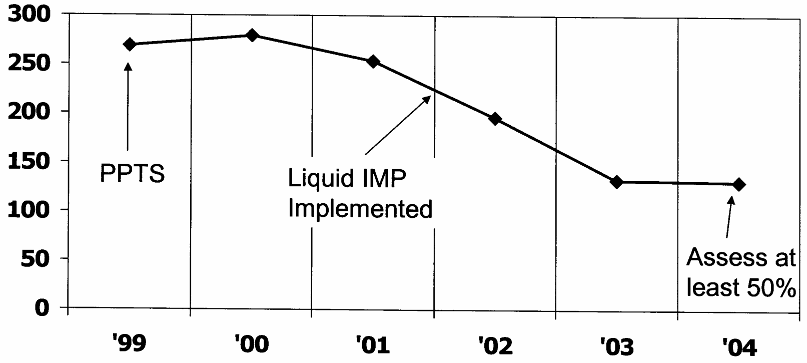
API

AOPL

Exhibit 2

Total Incidents, All Causes

(with pertinent milestones)



API

AOPL

AGA American Gas Association

AOPL

American Petroleum Institute

American Public Gas Association

INGAA

March 7, 2006

Stacey L. Gerard
Associate Administrator of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
400 7th St. SW
Washington, DC 20590

Re: Request for Operator Qualification (OQ) Program Modifications and Clarifications (Title 49 Part 192 Subpart N & 195 Subpart G)

Dear Ms. Gerard:

The member companies of AGA, AOPL, APGA, API, and INGAA represent the majority of the U.S. hazardous liquid and natural gas pipeline infrastructure. We support and appreciate the efforts of the Pipeline and Hazardous Materials Safety Administration (PHMSA) to review and make appropriate modifications to PHMSA's Operator Qualification (OQ) program in anticipation of possible Congressional consideration of pipeline safety legislation this year.

At the PHMSA OQ public meeting on December 15, 2005, pipeline operating companies gave presentations describing the efforts and accomplishments of the pipeline industry with respect to the OQ program. These testimonies, along with comments from industry associations, revealed that pipeline operator qualification programs are effectively meeting or exceeding PHMSA's high expectations.

We believe that the OQ requirements in the Pipeline Safety Improvement Act of 2002 and several OQ issues expressed by the PHMSA and NTSB do not require major changes to the rule. For your consideration, we propose on Attachment 1, minor rule changes to address all but one of the issues discussed in PHMSA's latest concept paper on strengthening OQ.

We generally support clarifying the regulatory requirements for training and requalification intervals. The concept paper issue not addressed in our proposal is new construction. We believe that regulations, technical standards and codes already exist that establish quality control processes and ensure integrity of new construction. These procedures address key safety areas of new construction more effectively than could be done by the OQ program. Our review of several years of PHMSA pipeline safety data showed no indication of a major trend or significant level of accidents attributable to work error during new pipeline installation. Therefore, we believe the new construction OQ concept would create undue burdens on operators without providing discernable benefits to safety.

We also believe that audit protocols must be strictly based on the rule requirements, must not impose excessive administrative burdens to prove compliance, and must be uniformly applied. With this in mind, we request that PHMSA add language to the "Headquarters OQ Inspection Protocol" that would provide an operator the option to have a written qualification program that strictly complies with either 49 CFR 192.801 or 195.501. Also, the protocols should state that usage of all or part of ASME B31Q is acceptable as a method to assure compliance, as was stated by PHMSA during the public meeting. This would provide the flexibility many operators are seeking by providing the operator implementation choices using clear stated practices.

We look forward to working with PHMSA and the rest of the pipeline industry to improve the OQ regulations and fashion a progressive, performance based OQ program. By bringing together the best practices from every segment of our industry, we will all continue to improve pipeline safety.

Sincerely,

Richard Bird
Group VP, Liquids Transportation
Enbridge Energy Partners LP
Chairman, API Pipeline Segment

Ronald W. Jibson
Vice President of Operations
Questar Gas Company

Tom Sewell
Director of Operations
Clearwater Gas System
Chairman APGA Operations Committee

Michael Mears

Mike Mears
Vice President, Transportation
Magellan Midstream Partners LP
Chairman, Association of Oil Pipe Lines

Jeffrey L. Barger
Vice President, Operations
Dominion Transmission, Inc.

David N. Parker

David N. Parker
President and CEO
American Gas Association

Donald Santa
President
Interstate Natural Gas Association
of America

Benj. S. Cooper

Benjamin S. Cooper
Executive Director
Association of Oil Pipe Lines

Red Cavaney
President and CEO
American Petroleum Institute

Bert Kalisch

Bert Kalisch
President and CEO
American Public Gas Association

Attachment 1 – Proposed Rule Modifications

Proposal:
We believe that these modifications to the rule will meet the needs of NTSB, allow companies to manage resources more effectively and will enhance the OQ rule. Below is a summary of our recommendations:

1. Provided language to address "Evaluation Interval" (192.805 and 195.505)
2. Provided language to address "Training" (192.805 & 195.505)

Recommended new language:
We are providing the following suggestions in revising the regulatory language to make these improvements (changes from the text of the current language are in *italic* and underlined):

49 CFR 192 Subpart N

§192.805 Qualification program

Each operator shall have and follow a written qualification program. The program shall include provisions to:
(a) Identify covered tasks;
(b) Ensure through evaluation that individuals performing covered tasks are qualified;
(c) Allow individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified;
(d) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an incident as defined in Part 191;
(e) Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;
(f) Communicate changes that affect covered tasks to individuals performing those covered tasks;
(g) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed. *The evaluation interval for each covered task may not exceed 5 years;*
(h) After December 16, 2004, provides training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities. *The operator's plan must identify circumstances in which training is required and should include situations where the individual:*

1) *Is seeking qualification for a covered task not previously performed;*
2) *Is seeking qualification for a covered task outside their knowledge and skills;*
3) *Has had a qualification suspended or revoked;*
4) *Fails an evaluation for qualification;*
5) *Requires new or different knowledge or skills to perform a covered task;*
6) *Will utilize new equipment or procedures to perform a covered task; or*
7) *Has completed an evaluation and requires additional knowledge or skills to implement specific requirements that are outside the scope of the evaluation.; and*

(i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the Administrator or state agency has verified that it complies with this section.

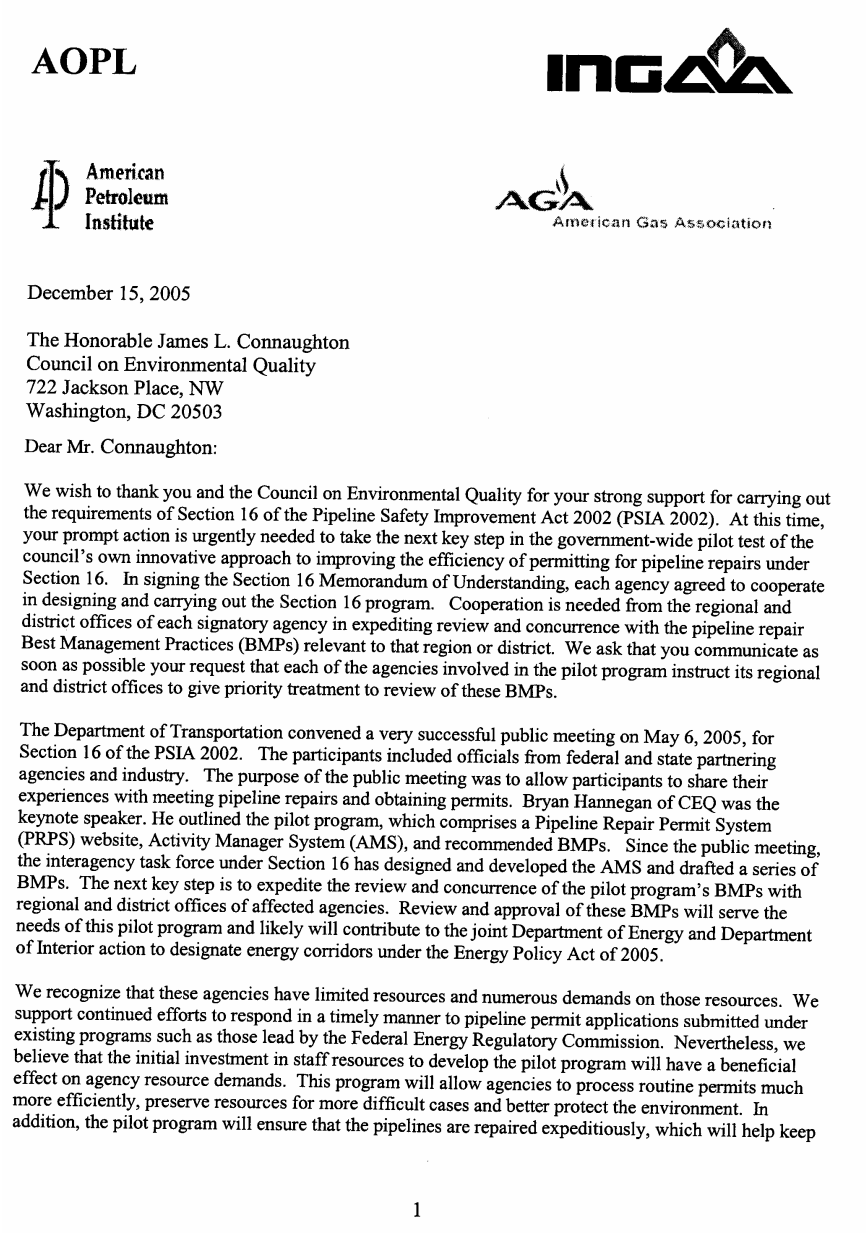
49 CFR 195 Subpart G

§195.505 Qualification program

(a) Identify covered tasks;
(b) Ensure through evaluation that individuals performing covered tasks are qualified;
(c) Allow individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified;
(d) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an incident as defined in Part 191;
(e) Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;
(f) Communicate changes that affect covered tasks to individuals performing those covered tasks;
(g) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed. *The evaluation interval for each covered task may not exceed 5 years;*
(h) After December 16, 2004, provides training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities. *The operators plan must identify circumstances in which training is required and should include situations where the individual:*

1) *Is seeking qualification for a covered task not previously performed;*
2) *Is seeking qualification for a covered task outside their knowledge and skills;*
3) *Has had a qualification suspended or revoked;*
4) *Fails an evaluation for qualification;*
5) *Requires new or different knowledge or skills to perform a covered task;*
6) *Will utilize new equipment or procedures to perform a covered task; or*
7) *Has completed an evaluation and requires additional knowledge or skills to implement specific requirements that are outside the scope of the evaluation; and*

(i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the Administrator or state agency has verified that it complies with this section.



AOPL

INGAA

American
Petroleum
Institute

AGA
American Gas Association

December 15, 2005

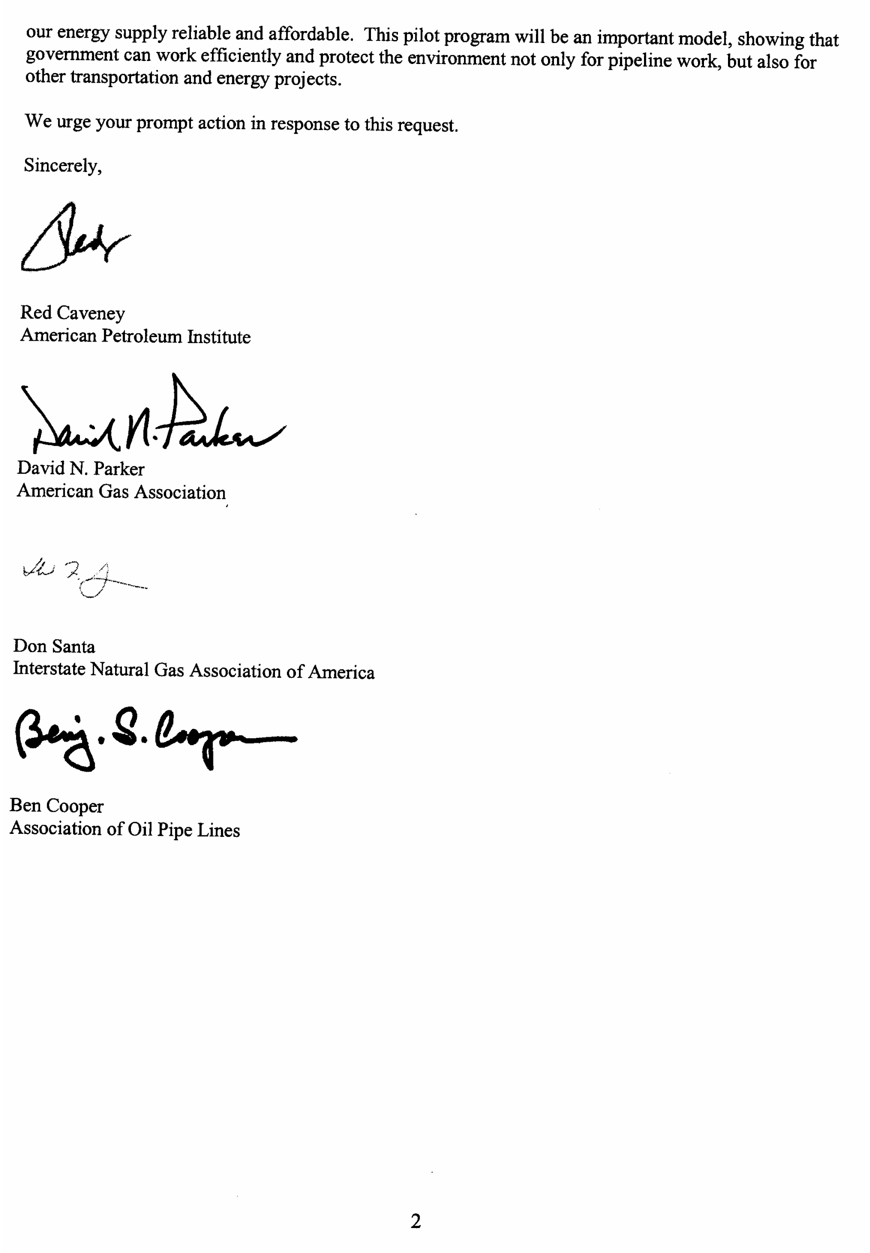
The Honorable James L. Connaughton
Council on Environmental Quality
722 Jackson Place, NW
Washington, DC 20503

Dear Mr. Connaughton:

We wish to thank you and the Council on Environmental Quality for your strong support for carrying out the requirements of Section 16 of the Pipeline Safety Improvement Act 2002 (PSIA 2002). At this time, your prompt action is urgently needed to take the next key step in the government-wide pilot test of the council's own innovative approach to improving the efficiency of permitting for pipeline repairs under Section 16. In signing the Section 16 Memorandum of Understanding, each agency agreed to cooperate in designing and carrying out the Section 16 program. Cooperation is needed from the regional and district offices of each signatory agency in expediting review and concurrence with the pipeline repair Best Management Practices (BMPs) relevant to that region or district. We ask that you communicate as soon as possible your request that each of the agencies involved in the pilot program instruct its regional and district offices to give priority treatment to review of these BMPs.

The Department of Transportation convened a very successful public meeting on May 6, 2005, for Section 16 of the PSIA 2002. The participants included officials from federal and state partnering agencies and industry. The purpose of the public meeting was to allow participants to share their experiences with meeting pipeline repairs and obtaining permits. Bryan Hannegan of CEQ was the keynote speaker. He outlined the pilot program, which comprises a Pipeline Repair Permit System (PRPS) website, Activity Manager System (AMS), and recommended BMPs. Since the public meeting, the interagency task force under Section 16 has designed and developed the AMS and drafted a series of BMPs. The next key step is to expedite the review and concurrence of the pilot program's BMPs with regional and district offices of affected agencies. Review and approval of these BMPs will serve the needs of this pilot program and likely will contribute to the joint Department of Energy and Department of Interior action to designate energy corridors under the Energy Policy Act of 2005.

We recognize that these agencies have limited resources and numerous demands on those resources. We support continued efforts to respond in a timely manner to pipeline permit applications submitted under existing programs such as those lead by the Federal Energy Regulatory Commission. Nevertheless, we believe that the initial investment in staff resources to develop the pilot program will have a beneficial effect on agency resource demands. This program will allow agencies to process routine permits much more efficiently, preserve resources for more difficult cases and better protect the environment. In addition, the pilot program will ensure that the pipelines are repaired expeditiously, which will help keep



our energy supply reliable and affordable. This pilot program will be an important model, showing that government can work efficiently and protect the environment not only for pipeline work, but also for other transportation and energy projects.

We urge your prompt action in response to this request.

Sincerely,

Red Caveney
American Petroleum Institute

David N. Parker

David N. Parker
American Gas Association

Don Santa
Interstate Natural Gas Association of America

Benj. S. Cooper

Ben Cooper
Association of Oil Pipe Lines

MR. HALL. Thank you, sir.

The Chair recognizes Ms. Epstein, Senior Engineer, Oil and Gas Industry Specialist, Cook Inlet Keeper, for 5 minutes to summerize your testimony please. Thank you.

MS. EPSTEIN. All right. Good afternoon. Thank you, Mr. Chairman, Mr. Boucher, members of the subcommittee and the full committee, and thanks to our legislative aides who are here, as Chairman Hall acknowledged.

Cook Inlet Keeper is a non-profit conservation and safety organization and part of the Water Keeper Alliance of 130-plus groups headed by Bobby Kennedy, Jr. My background includes serving on the U.S. Department of Transportation Advisory Committee for oil pipelines since 1995 and testifying before Congress four times on pipeline safety.

I also am testifying today on behalf of the Pipeline Safety Trust, an organization that came into being after the Olympic pipeline tragedy in Bellingham, Washington in 1999, which left three young people dead, destroyed a salmon stream, and cost millions of dollars in economic disruption.

Today, I will discuss the oversight and legislative improvements needed to guide PHMSA and State pipeline agency actions until the next reauthorization.

Before I begin, however, I would like to commend the progress PHMSA has made under its current leadership and that of the many pipeline companies who are maintaining their pipelines in ways that go beyond the minimum Federal requirements. Everyone should celebrate this progress while acknowledging that continuous evaluation improvement can make pipelines safer yet, which will, in turn, increase the public's trust. We do support prompt reauthorization and also believe the current statute is working well.

One of our highest priorities is to ensure that local governments and the public have accurate information which allows them to independently evaluate, sometimes with technical assistance, the safety of nearby pipelines. PHMSA has made progress in this area, but some of the most important public information pieces still are missing. Congress needs to make available: one, pipeline maps for emergency responders, planners, zoning officials, and residents while still respecting security needs; two, increase public information on pipeline inspections and enforcement actions; and three, operator reports of all over-pressurization incidents, which are among the best measures of whether pipeline companies have good control over their systems.

Along with this additional information, Congress needs to ensure that Section 9 of the 2002 law is carried out. This section states that pipeline safety information grants up to $50,000 will be available to use, for example, by statewide pipeline stakeholder organizations such as those that exist now in Washington and Kentucky, by organizations needing technical assistance to comment on, or participate in, rule or industry standard development, and by community groups seeking to understand technical and regulatory issues following pipeline accidents. As time goes on, there have been numerous missed opportunities for effective public involvement as a result of the lack of grants to date, and I appreciate Mr. Boucher's and Ms. Gerard's comments on that topic today.

As you know, on March 2nd of this year, the largest oil spill to date, on Alaska's North Slope, of 200,000 gallons or more was discovered out of Caribou Crossing located in a PHMSA-recognized high-consequence area. This spill came from a BP transmission pipeline that was exempt from PHMSA regulations. According to BP in the Anchorage Daily News, the pipeline "had known interior and exterior corrosion damage. Because of this, BP had downgraded the maximum pressure allowed within the line," making it a low-stress line. Ironically, lower pressure takes the line out of the Federal regulatory system. Figure C, which everyone can view in my written testimony, shows the extensive clean-up at the site.

It is clear from figure C that low-stress hazardous liquid transmission pipelines can result in significant damage and cost when there are releases. PHMSA needs to remove the low-stress hazardous liquid pipeline exemption from the regulations, and I am pleased with Ms. Gerard's answers to questions on this topic.

While low-stress lines may release hazardous liquids at a rate less than other transmission lines, this winter's spill shows that they pose comparable environmental hazards and should be regulated similarly. And that is an important point.

On enforcement, it is not enough for PHMSA to pursue consent agreements and enforcement actions against individual violators if these actions do not convey to the industry as a whole that all operators are at risk of serious penalties for non-compliance and/or incidents. PHMSA needs to increase its use of judicial enforcement and allow qualified State pipeline safety officials to pursue enforcement actions against any State pipeline operators.

Our written testimony provides much-needed evidence of the deficiencies in PHMSA's current enforcement program. As one example, the subcommittee should note that the lowest of the Environmental Protection Agency's pipeline operator penalties is nearly 12-times larger than the largest PHMSA-collected penalty from March 7, 2002 through March 31, 2006.

Those portions of transmission pipelines that could affect high-consequence areas, or HCAs, are subject to the greatest regulatory oversight by PHMSA to date. Due to resource limitations, certain HCA areas were overlooked by PHMSA to date, namely parks and refuges and fishable and swimable waters for hazardous liquid pipelines.

Additionally, Congress needs to add new language in the statute to include culturally and historically significant resources as HCAs.

For liquid pipelines, these expansions should not involve assessing many more sections of pipelines than are tested now. The majority of deaths and injuries from pipelines occur from incidents on the distribution pipeline systems that bring gas to towns, businesses, and homes. From 2001 through 2005, 61 people died along these pipelines, and 236 were injured. Congress needs to adopt a deadline for regulations to be completed on distribution pipeline integrity management and should mandate an excess flow valve requirement for new and replacement distribution pipelines as recommended by the NTSB, the International Association of Firefighters, and the International Association of Fire Chiefs, and this will be at a cost of $5 to $15 per EFV, or excess flow valve.

Thank you very much for your interest in pipeline safety and for inviting me to present here today. Please feel free to contact me at any time with your questions.

[The prepared statement of Lois N. Epstein, P.E. follows:]

PREPARED STATEMENT OF LOIS N. EPSTEIN, P.E., SENIOR ENGINEER, OIL AND GAS INDUSTRY SPECIALIST, COOK INLET KEEPER, ON BEHALF OF PIPELINE SAFETY TRUST

Congress should pursue the following oversight and reauthorization items:

1. Public information – direct PHMSA to:
    a) Reinstate public access to the National Pipeline Mapping System,
    b) Create a web-based enforcement document docket,
    c) Remove regulatory exemptions from over-pressurization reporting
2. Ensure that PHMSA develops oil pipeline shut-off valve location and performance standards
3. Ensure that PHMSA issues leak detection system performance standards for oil pipelines in High Consequence Areas
4. Reauthorize and ensure that Congress appropriates money for Pipeline Safety Information Grants
5. Remove the “low-stress” oil pipeline exemption
6. Require PHMSA to provide web-based data on federal and state pipeline inspection and enforcement activities and an annual report to Congress on civil and criminal enforcement including penalty issuance and collection, and allow state regulators to pursue enforcement on interstate pipelines
7. Direct PHMSA to expand High Consequence Areas so they include cultural and historic sites, parks and refuges, and fishable and swimmable waters
8. Mandate a deadline for distribution pipeline integrity management regulations to be in place
9. Maintain the current natural gas transmission pipeline integrity management reassessment interval

Good morning. My name is Lois Epstein and I am a licensed engineer and an oil and gas industry specialist with Cook Inlet Keeper in Anchorage, Alaska. Cook Inlet Keeper is a nonprofit, membership organization dedicated to protecting Alaska’s 47,000 square mile Cook Inlet watershed, and a member of the Waterkeeper Alliance of 130+ organizations headed by Bobby Kennedy, Jr. My background in pipeline safety includes membership since 1995 on the U.S. Department of Transportation's Technical Hazardous Liquid Pipeline Safety Standards Committee which oversees the Pipeline and Hazardous Materials Safety Administration's (PHMSA's) oil pipeline activities and rule development, testifying before Congress in 1999, 2002, 2004, and last month on pipeline safety, and researching and analyzing the performance of Cook Inlet's 1000+ miles of pipeline infrastructure by pipeline operator and type.1 I have worked on environmental and safety issues for over 20 years for two private consultants, the U.S. Environmental Protection Agency, Environmental Defense, and Cook Inlet Keeper.

My work on pipelines in Alaska allows me to see how well the policies developed in DC operate in the "real world." The Cook Inlet watershed, which includes Anchorage and encompasses an area larger than Virginia, is where oil and gas first was developed commercially in Alaska beginning in the late 1950s. Cook Inlet is an extraordinarily scenic and fisheries- and wildlife-rich, region, so ensuring that fisheries and the environment remain in a near-pristine condition is an important Alaskan value.

I also am a part-time consultant for the Pipeline Safety Trust, located in Bellingham, Washington, and my testimony today reflects both Cook Inlet Keeper and the Pipeline Safety Trust's views. Carl Weimer, the Executive Director of the Pipeline Safety Trust, is in Texas this week speaking at the annual American Petroleum Institute pipeline conference, so he could not be with us today. The Pipeline Safety Trust came into being after the 1999 Olympic Pipe Line tragedy in Bellingham, Washington which left three young people dead, wiped out every living thing in a beautiful salmon stream, and caused millions of dollars of economic disruption to the region. After investigating this tragedy, the U.S. Department of Justice (DOJ) recognized the need for an independent organization which would provide informed comment and advice to both pipeline companies and government regulators and would provide the public with an independent clearinghouse of pipeline safety information. The federal trial court agreed with DOJ's recommendation and awarded the Pipeline Safety Trust $4 million that was used as an initial endowment for the long-term continuation of the Trust's mission.

Background

The Pipeline Safety Improvement Act of 2002 became law on December 17, 2002 following two particularly tragic pipeline accidents: in Bellingham, Washington in June 1999 and near Carlsbad, New Mexico in August 2000. The 2002 law contains some needed improvements but, like many acts of Congress, it represents a compromise among competing interests. As a result, safety will be improved, but not necessarily by as much or as fast as the public would like.

To put my presentation into context, the graphs below display the performance of the pipeline industry over time based on reported incidents and incidents/mile (the latter multiplied by appropriate factors for graphical display purposes). As you can see from the hazardous liquid pipeline data displayed in Figure 1, reported hazardous liquid pipeline incidents began dropping after 1994. 1994 is two years after Congress imposed mandatory requirements on the Office of Pipeline Safety (OPS) – now part of PHMSA – to prevent releases that impacted the environment, as opposed to releases which solely affect safety. From Figure 1, it appears that natural gas distribution pipeline incidents are trending slightly upward, while natural gas transmission pipeline incidents clearly are increasing. These upward trends may in part be an artifact of the recent increases in the price of natural gas which, in turn, increases the number of incidents above reporting thresholds (due to the cost of lost gas).

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[1] See *Lurking Below: Oil and Gas Pipeline Problems in the Cook Inlet Watershed*, 28 pp. plus appendices, 2002, and follow-up reports in 2003 and 2005. www.inletkeeper.org/pipelines.htm

Figure 1

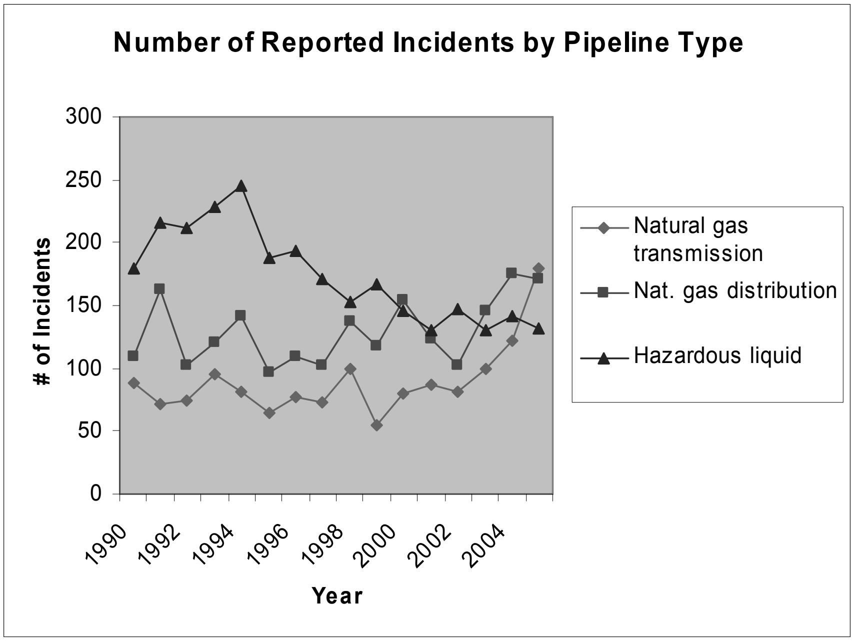

Figure 2 shows incidents divided by, or normalized by, pipeline mileage, which is a better way of measuring performance than the number of incidents alone since it accounts for changes in the number of incidents based on increased or decreased pipeline mileage. What is important to notice in Figure 2 is not the number of incidents per mile, but the trends this graph shows. The graph reinforces the improving performance of hazardous liquid pipelines, with a clear downward trend. Natural gas distribution pipelines do not show an upward or a downward trend in performance. Natural gas transmission pipelines, however, show a clear increase in the number of incidents per mile (again, at least some of this increase may be an artifact of the recent increase in natural gas prices). As I stated in my June 15, 2004 testimony before the Senate Commerce Committee, however:

> The most important rule issued as a result of the 2002 law, the natural gas transmission pipeline integrity management rule published on December 15, 2003…will not reduce incidents on those lines for several years and it's unclear how much of a reduction we can expect. This is true for several reasons. First, the law requires baseline integrity assessments to occur within 10 years, with 50% of the assessments occurring within 5 years of the law's enactment; this long timeframe will delay the benefits. Second, because the rule only applies to an estimated 7% of transmission pipelines,[2] by 2007 (i.e., five years after the law's enactment) we may
> expect only a 3.5% reduction in incidents, though the incidents that do occur should take place in areas of lesser consequences. Third, since the rule allows the use of

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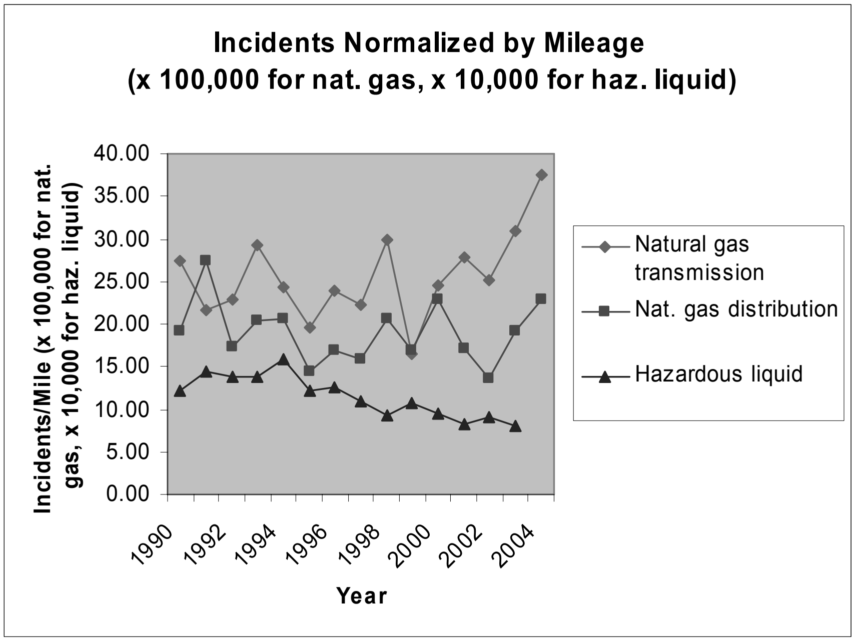
[2] OPS states in the preamble to the rule "that about 22,000 miles of gas transmission pipelines are located in the [High Consequence Areas] in a network of 300,000 miles of gas transmission pipeline." (68 Federal Register 69815, December 15, 2003)

not-fully-proven methodologies (i.e., “direct assessment” and “confirmatory direct assessment”), we need to wait several years to see whether OPS’ approach to this rule will result in a meaningful reduction in incidents.

Figure 2



Taking into account the different multipliers used, Figure 2 also shows that hazardous liquid transmission pipelines have a reported higher incident/mile rate than either type of natural gas pipeline, however the reporting thresholds for the different types of pipelines also differ.

Issues to Address During Oversight and Reauthorization

Based on the data shown in Figures 1 and 2, PHMSA’s reported performance to overseers including its federal advisory committees, the U.S. Government Accountability Office, and members of Congress, and a key recent incident on the North Slope of Alaska, I will discuss the oversight and legislative improvements needed to guide PHMSA and state pipeline agency actions until the next reauthorization.

Before I begin with recommended changes, I would like to commend the progress OPS/PHMSA has made under its current leadership. For the first time, hazardous liquid (i.e., oil) and natural gas transmission pipelines must be internally inspected, and rulemaking is proceeding to include integrity management requirements for gas distribution pipelines, where the majority of deaths and injuries occur. Pipeline operators now have clear requirements for communicating to the public and local governments, and PHMSA has unveiled valuable new additions to its own website and communication programs. Perhaps just as significant, many forward-thinking pipeline companies have taken pipeline safety seriously enough that they are now leading by example and operating and maintaining their pipelines in ways that go beyond the minimum federal standards. Everyone should celebrate this progress, while acknowledging that continuous evaluation and improvement can make pipelines considerably safer yet and thereby restore the public's trust in pipelines.

With respect to PHMSA oversight, I will discuss:

- Public information access – pipeline maps, inspection and enforcement activities, and over-pressurization reporting,
- Oil pipeline shut-off valve location and performance standards, and
- Leak detection system performance standard(s).

With respect to reauthorization needs, I will cover the following:

- Pipeline Safety Information Grants,
- Removal of the "low-stress" oil pipeline exemption,
- Enforcement,
- High Consequence Areas,
- Distribution pipeline integrity management, and
- Natural gas transmission pipeline integrity management reassessments.

Public information. One of the public interest community's highest priorities is to ensure that there is accurate information easily available to local governments and the public to allow them to independently evaluate – sometimes with technical assistance – the safety of nearby pipelines. PHMSA has made good progress in this area, but some of the most important information pieces still are missing.

Pipeline Maps – Maps that allow local government emergency responders, planners, and zoning officials to know where pipelines are in relation to housing developments and other infrastructure are critical to prevent pipeline damage and increase safety. Maps that allow the public to see the locations of nearby pipelines also are the best way to capture the public's attention regarding pipeline safety, increase their awareness of pipeline damage, and enlist them to be the eyes that help prevent damage. Maps also allow home-buyers and businesses to decide their own comfort level with living near pipelines.

The Pipeline Safety Improvement Act of 2002 required pipeline companies to provide PHMSA with data for the web-based National Pipeline Mapping System (NPMS) so maps could be available for the above purposes. Unfortunately after the September 11th, 2001 terrorist attacks, the NPMS became a password-protected system that required users to agree not to share the NPMS information with anyone else. The NPMS thus is not available to the public, and the system is largely useless for local governments because pipeline location information cannot be added to local Global Positioning Systems or planning maps due to the non-disclosure requirement.

The removal of NPMS maps from the web out of fear that terrorists may use them to find targets flies in the face of common sense. Major malls and stadiums, which are tempting targets, have no such non-disclosure requirement. Additionally, the locations of pipelines are no secret – in fact 49 CFR 195.410 requires that "Markers must be located at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of each buried line so that [a pipeline's] location is accurately known." All that has been accomplished by removing maps from the web is to increase the problems of encroachment near pipelines, unintentional damage to pipelines, and public skepticism about pipeline safety.

The removal of the NPMS from the web also has caused some states, such as Washington and Texas, to spend limited state dollars to duplicate PHMSA's mapping system so that local governments and the public can have access to this valuable information.

For these reasons, Congress should direct PHMSA to reinstate access to the NPMS so local governments can plan and the public can be aware of the pipelines that run through its midst.

Information on Inspection and Enforcement Activities – One of the most important functions that PHMSA provides is its ongoing independent inspection of pipeline companies' operations, maintenance, and training programs. Unfortunately, no portion of PHMSA's inspection findings are available for local government or the public to review, leaving everyone outside of PHMSA and operators guessing the condition of pipelines and even if inspections are taking place.

The pipeline industry itself complains about this lack of transparency. Individual companies know when they have been inspected, but often have to wait months or years to learn the outcome of inspections and, if there are no problems, they may hear absolutely nothing. This lengthy and frequently non-existent feedback system for operators is unfair, and does not improve safety the way a timely feedback system would.

There should be a coversheet for each inspection that includes basic information such as pipeline segment inspected, inspection date, concerns noted, and corrections required. If this basic information, along with associated correspondence between PHMSA and operators were provided on a web-based docket system that could be searched by state or operator name, it would go a long way toward increasing trust in pipeline safety.

For non-compliance-related enforcement actions, PHMSA should create a web-based enforcement document docket where the public could view enforcement as it progresses. The docket would include PHMSA's Notices of Probable Violation, operators' responses, transcripts of hearings, and final decisions. This would provide the public with a transparent enforcement system that would either instill confidence in PHMSA's efforts, or provide the documentation needed to improve the system.

Over-Pressurization Reporting – One of the clearest measurements of whether a pipeline operator has good control over its pipeline system is the frequency that it allows the system to exceed the maximum allowable operating pressure plus a permitted accumulation pressure for natural gas pipelines, or 110% of the maximum operating pressure for liquid pipelines. Unfortunately, the vast majority of these events are not required to be reported to PHMSA, so neither the federal government nor the public can use this information to determine whether pipeline operators are causing unwarranted stress on their lines and therefore need greater scrutiny. For these reasons, the exemptions from reporting these events contained in 49 CFR 191.23(b) and 49 CFR 195.55(b) should be removed.

Oil pipeline shut-off valve location and performance standards. In 1992, 1996, and 2002, Congress required OPS to "survey and assess the effectiveness of emergency flow restricting devices…to detect and locate hazardous liquid pipeline ruptures and minimize product releases."[3] Following this analysis, Congress required OPS to "prescribe regulations on the circumstances under which an operator of a hazardous liquid pipeline facility must use an emergency flow restricting device (emphasis added)."[4]

OPS/PHMSA never issued a formal analysis on emergency flow restricting device (EFRD) effectiveness. Instead, in its hazardous liquid pipeline integrity management rule,[5] OPS rejected the comments of the National Transportation Safety Board, the U.S.

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[3] 49 USC 60102(j)(1).

[4] 49 USC 60102(j)(2).

[5] 49 CFR 195.452(i)(4).

Environmental Protection Agency, the Lower Colorado River Authority, the City of Austin, and Environmental Defense and chose to leave EFRD decisions up to pipeline operators (after listing in the rule various criteria for operators to consider). It is unlikely such an approach to EFRD use meets Congressional intent, partly because the approach is virtually unenforceable and not protective of important environmental assets such as rivers and lakes. At this time, Congress needs to reiterate its previous mandates to PHMSA on EFRD use.

Leak detection system performance standard(s). In its hazardous liquid transmission pipeline integrity management rule, PHMSA requires that operators have a means to detect leaks, but there are no performance standards for such a system. Similar to the situation for EFRD use, PHMSA listed in the rule various criteria for operators to consider when selecting such a device.[6] Again, such an approach is virtually unenforceable and not protective of important environmental assets such as rivers and lakes. Thus, Congress needs to direct PHMSA to issue a performance standard(s) for leak detection systems used by hazardous liquid pipeline operators to prevent damage to High Consequence Areas.

Pipeline Safety Information Grants. Section 9 of the 2002 law states that:

> The Secretary of Transportation may make grants for technical assistance to local communities and groups of individuals (not including for-profit entities) relating to the safety of pipeline facilities in local communities…The amount of any grant under this section may not exceed $50,000 for a single grant recipient. The Secretary shall establish appropriate procedures to ensure the proper use of funds provided under this section. (§ 60130(a)(1))

To date, PHMSA has not established any such procedures, nor has it had any success obtaining appropriated funds for this purpose. As time goes on, there are missed opportunities for use of these funds, e.g., such funds might have helped community organizations understand the technical and regulatory issues associated with the Tucson gasoline pipeline accident in July 2003, as well as the Kentucky-based state-wide organization working on the substantial Kentucky and Ohio River crude oil pipeline spill of January 2005. Likewise, such grants are needed to assist public interest groups in commenting on technical regulations and to participate in technical standards development.

Cook Inlet Keeper, the Pipeline Safety Trust, and other public interest organizations urge Congress to make certain that this section of the 2002 law is carried out as intended. Congress needs to ensure that authorization of this program continues and money to fund the grants is appropriated.

Removal of the "low-stress" oil pipeline exemption. Last month on March 2, 2006 the largest oil spill to date on the North Slope of Alaska of 200,000 gallons or more was discovered at a caribou crossing located in a PHMSA-recognized High Consequence Area. This spill came from a BP crude oil transmission pipeline that was exempt from PHMSA regulations because it was a "low-stress" hazardous liquid pipeline that met the following criteria: it did not transport a highly volatile liquid (HVL), it was located in a rural area, and it was outside a waterway currently used for commercial navigation.[7] According to BP, the pipeline "had known interior and exterior corrosion damage.

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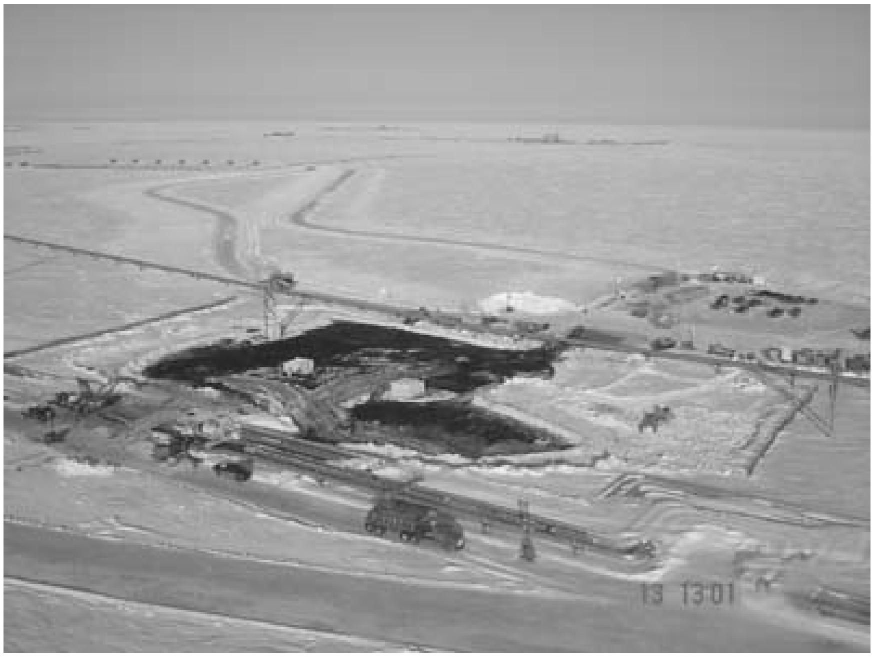
[6] 49 CFR 195.452(i)(3).

[7] 49 CFR 195.1(a)(3).

Because of this, BP had downgraded the maximum pressure allowed within the line…"[8] Figure 3 shows the extensive cleanup operation which occurred (and is still ongoing) at this site.

Figure 3



Oil recovery efforts, March 13, 2006, Unified Command photo.

It's clear from Figure 3 that "low-stress" hazardous liquid transmission pipelines can cause significant damage when there is a release. Congress recognized this fact and included the following provision in the pipeline safety law:

> **Prohibition against low internal stress exception.** The Secretary may not provide an exception to this chapter for a hazardous liquid pipeline facility only because the facility operates at low internal stress.[9]

To provide necessary protection of the environment, Congress now needs to direct PHMSA to remove the "low-stress" hazardous liquid pipeline exemption from the regulations, perhaps retaining only the "low-stress" exemption for HVL lines. While low-stress lines may release hazardous liquids at a rate that is less than other transmission lines, this winter's spill on the North Slope shows that they pose comparable environmental hazards and should be regulated similarly.

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[8] "Workers respond to Prudhoe spill: Leak may be one of largest in 29 years of production," Wesley Loy, Anchorage Daily News, March 4, 2006.

[9] 49 USC 60102(k).

Enforcement. The public and, presumably, pipeline operators have very little evidence that the increased penalties contained in Section 8 of the 2002 pipeline safety law are being consistently used and collected by PHMSA to send a message to pipeline operators that violations are both unacceptable and costly. This reality, along with PHMSA's relative lack of judicial enforcement actions and the current inability of qualified states to pursue pipeline safety enforcement actions, leads to a still- problematic enforcement environment for pipelines. *It is not enough for PHMSA to pursue consent agreements and enforcement actions against individual violators (e.g., Kinder Morgan following multiple releases[10]) if these actions do not convey to the industry as a whole that all operators are at risk of serious penalties for non-compliance and/or incidents.*

Cook Inlet Keeper and the Pipeline Safety Trust propose two modest and one substantive and significant legislative changes at the end of this section in order to ensure improved enforcement accountability, visibility, and effectiveness.

As evidence of current problems with pipeline safety enforcement, consider that:

- In my response to follow-up questions from Senator Breaux after the June 15, 2004 Senate Commerce Committee hearing, I stated that PHMSA needs to pursue several, high-profile preventive enforcement actions related to pipeline safety requirements in instances where there have not been releases. These include violations of corrosion prevention requirements, improper performance of direct assessment (a less-proven means of integrity assessment than smart pigging which PHMSA allows natural gas transmission pipelines to use), exposed pipelines, poorly performed repairs, etc. While PHMSA occasionally pursues enforcement actions related to these types of violations, practically no one except the violator knows that it has done so because penalties are low, media attention is limited or non-existent, it is hidden on the PHMSA website if it is visible at all, etc.
- PHMSA can pursue enforcement actions for interstate pipeline violations but qualified state regulators cannot, though the large number of state regulators can assist in inspection and analysis of violations. In fiscal year 2003, PHMSA employed approximately 75 inspectors[11] who were responsible for oversight of roughly 6,000 miles of interstate transmission pipeline each, a very large number of miles per inspector. Additionally, federal inspectors may not be as aware of certain technical, geographic, and even management issues associated with interstate pipelines as state regulators because of state officials' proximity to the lines.
- The Bellingham, WA proposed penalty in 2000 was $3.02 million, which was negotiated down to $250,000 nearly five years later. The Carlsbad, NM proposed penalty in 2001 was $2.52 million however, to date, no penalty has been collected.
- In contrast to PHMSA, the U.S. Environmental Protection Agency (EPA) has issued and collected several recent, multi-million dollar penalties from hazardous liquid pipeline companies for their releases (EPA cannot use its capabilities to enforce against natural gas pipeline releases). These EPA penalties are shown in the following table. *Note that the lowest of the EPA pipeline penalties is still nearly 12 times larger than the largest PHMSA-collected penalty from March 7, 2002 – March 31, 2006.*[12]

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[10] Pipeline and Hazardous Materials Safety Administration, CPF No. 5-2005-502H.

[11] GAO, op. cit., p. 12.

[12] Response letter from Brigham A. McCown, PHMSA Acting Administrator, to Congressmen John D. Dingell and Rick Boucher, April 18, 2006.

Company	Date	Penalty	Summary of Violations
Mobil E & P	8/04	$5.5 mill.	Oil and produced water releases, inadequate prevention and control, failure to notify EPA of releases
Olympic Pipeline/Shell	1/03	>$5 mill. - Olympic >$10 mill. – Shell	> 230,000 gal. of gasoline released, 3 human deaths, over 100,000 fish killed
Colonial Pipeline	4/03	$34 mill.	1.45 mill. gal. of oil released in 5 states from 7 spills (from corrosion, mechanical damage, and operator error)
ExxonMobil	9/02	$4.7 mill.	Approx. 75,000 gal. of crude oil released, fouling a river and nearby areas
Koch Industries, Inc.	1/00	>$35 mill.	Approx. 3 mill. gal. of oil released in 6 states (from corrosion of pipelines in rural areas)

As a result of these ongoing problems with PHMSA enforcement, Cook Inlet Keeper and the Pipeline Safety Trust recommend that the federal pipeline safety statute be amended to:

1. require PHMSA to provide web-based data on federal and state pipeline inspection and enforcement activities, including basic information such as pipeline segment inspected, inspection date, concerns noted, and corrections required as discussed above;
2. require PHMSA to submit an annual report to Congress on civil and criminal pipeline safety enforcement, including penalty issuance, collection, and reasons for significant penalty reductions; and,
3. allow qualified state pipeline safety officials to pursue enforcement actions against interstate pipeline operators. This recommendation, while significant, is necessary to maximize use of state and federal regulatory resources in the service of pipeline safety.

High Consequence Areas. Those portions of transmission pipelines that could affect High Consequence Areas (HCAs) are subject to the greatest regulatory oversight, i.e., the hazardous liquid and natural gas transmission pipeline integrity management rules. Currently, HCAs for hazardous liquid transmission pipelines cover commercially navigable waterways, high population areas, and drinking water and ecological resources. HCAs for natural gas transmission pipelines cover high-density and other frequently-populated areas. According to industry-submitted data, approximately 40% of hazardous liquid transmission lines could affect HCAs, but over 80% of hazardous liquid transmission pipelines likely will be smart-pigged or pressure-tested for pipeline integrity.[13] If, in fact, over 80% of the hazardous liquid transmission lines meet the standards of the integrity management rule (including post-pigging repairs), that is an excellent step toward improved pipeline safety.

There are portions of hazardous liquid transmission pipelines that do not fall within the 40% of the lines that could affect HCAs which nevertheless should have the protection afforded by the integrity management rule. Congress needs to direct PHMSA to expand the definition of HCAs to include the following areas – parks and refuges, and fishable and swimmable waters.[14] For reasons that are obvious to most anyone, parks and refuges and fishable and swimmable waters are areas of unusually high environmental sensitivity. At the time of HCA rule development, OPS took a narrow view of HCAs, partly for resource reasons and partly because of the need to issue the rule in a timely fashion. At this point in time, PHMSA is better able to expand the HCA rule to cover parks and refuges and fishable and swimmable waters.

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[13] PHMSA Pipeline Integrity Workshop, Houston, Texas, May 17-18, 2005.

Additionally, in mandating identification of HCAs in the 1992 statute, Congress did not include language about HCAs covering culturally and historically significant resources. This is a clear gap in the current statute, which Congress now needs to address.

Distribution pipeline integrity management. The majority of deaths and injuries from pipelines occur from incidents on the distribution pipeline systems that bring gas to our towns, businesses, and homes. From 2001-2005, 61 people died along these pipelines and 236 were injured. PHMSA, states, industry, and private organizations have undertaken an aggressive work plan to come up with an integrity management program for distribution pipelines. The Phase 1 report on this plan was released in December 2005,[15] and all involved deserve thanks for their efforts. It is imperative that this plan now moves to the adoption of rules as soon as possible. Congress should adopt a deadline for regulations to be completed on this important issue.

The proposed distribution pipeline integrity management program poses one area of concern: the lack of a mandatory excess flow valve (EFV) requirement. Congress asked PHMSA to set standards for the circumstances in which excess flow valves should be required,[16] and the National Transportation Safety Board (NTSB) recommended that excess flow valve installation be mandatory in new construction and when existing service pipelines are replaced or upgraded.[17] The International Association of Fire Fighters and the International Association of Fire Chiefs supports this mandatory installation position. [18] The Pipeline Safety Trust commissioned an independent review of the literature and science on excess flow valves, and that review came to the same conclusion.[19]

The current Phase 1 report does not ask for mandatory EFV installation, but instead states that "It is not appropriate to mandate excess flow valves (EFV) as part of a high-level, flexible regulatory requirement. An EFV is one of many potential mitigation options."[20] Congress should ask PHMSA and the pipeline industry how they plan to explain to the families of those killed in the future because of the lack of a $5-15 excess flow valve how a "flexible regulatory requirement" protected their loved ones.

Natural gas transmission pipeline integrity management reassessments. The 2002 reauthorization of the pipeline safety statute included some prescriptive language covering natural gas transmission pipeline integrity management timeframes. This was needed because – even though the hazardous liquid pipeline integrity management program was developed through rulemaking – it was clear to those involved that the timeframes for baseline and reassessment integrity assessments for natural gas transmission pipelines were highly contentious and needed to be resolved by Congress for a rulemaking to move forward. Since it is now only 2 ½ years after the integrity management rule for natural gas transmission pipelines was issued and there have not been enough completed baseline assessments or any seven-year reassessments to know with any certainty the appropriate reassessment interval, it is not a sound technical decision to move forward with any changes to the Congressionally-mandated reassessment interval at this time. Additionally, the U.S. Government Accountability Office stated in its March 16, 2006 testimony that it would not complete its report on the reassessment interval until fall 2006, [21] further arguing against any change to the reassessment interval at this time.

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[14] The federal Clean Water Act goals are fishable, swimmable, and drinkable waters. HCAs currently ensure only drinkable waters.

[15] *Integrity Management for Gas Distribution: Report of Phase 1 Investigations*, December 2005 (http://www.cycla.com/opsiswc/docs/S8/P0068/DIMP_Phase1Report_Final.pdf).

[16] 49 USC 60110.

[17] National Transportation Safety Board Safety Recommendation P-01-1, 2. June 22, 2001 (http://www.ntsb.gov/recs/letters/2001/p01_1_2.pdf).

[18] Letter from the International Association of Fire Fighters and the International Association of Fire Chiefs to U.S. Department of Transportation Secretary Mineta, January 20, 2004, DOT Docket Management System #RSPA-2003-14455-49.

[19] *A Simple Perspective on Excess Flow Valve Effectiveness in Gas Distribution System Service Lines*, Richard B. Kuprewicz for the Pipeline Safety Trust, July 2005 (see http://www.pstrust.org/library/pdf/issuedEFV_Report.pdf).

[20] *Integrity Management for Gas Distribution: Report of Phase 1 Investigations*, op. cit., p. 14.

Summary

In conclusion, Congress should pursue the following oversight and reauthorization items:

10. Public information – direct PHMSA to:
    a) Reinstate public access to the National Pipeline Mapping System,
    b) Create a web-based enforcement document docket,
    c) Remove regulatory exemptions from over-pressurization reporting
11. Ensure that PHMSA develops oil pipeline shut-off valve location and performance standards
12. Ensure that PHMSA issues leak detection system performance standards for oil pipelines in High Consequence Areas
13. Reauthorize and ensure that Congress appropriates money for Pipeline Safety Information Grants
14. Remove the “low-stress” oil pipeline exemption
15. Require PHMSA to provide web-based data on federal and state pipeline inspection and enforcement activities and an annual report to Congress on civil and criminal enforcement including penalty issuance and collection, and allow state regulators to pursue enforcement on interstate pipelines
16. Direct PHMSA to expand High Consequence Areas so they include cultural and historic sites, parks and refuges, and fishable and swimmable waters
17. Mandate a deadline for distribution pipeline integrity management regulations to be in place
18. Maintain the current natural gas transmission pipeline integrity management reassessment interval.

Thank you very much for your interest in pipeline safety. Please feel free to contact me at any time with your questions or comments.

MR. HALL. Thank you for a good presentation.

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[21] *Gas Pipeline Safety: Preliminary Observations on the Integrity Management Program and 7-Year Reassessment Interval*, Testimony by Katherine Siggerud, U.S. Government Accountability Office, March 16, 2006, Highlights.

Mr. Kipp, we recognize you, as President of Common Ground Alliance, for 5 minutes. Thank you, sir.

MR. KIPP. Thank you. Good afternoon, Mr. Chairman and members of the subcommittee.

I am pleased to appear before you today to represent the CGA. In reduced time, I would like to focus on three issues.

The first, damage information reporting tool. Late last year, the CGA published its first report on damage data. This report can be found on our website. We are now in a position to draw some conclusions and provide trends and analysis on damage to our infrastructure. For example, our 2004 analysis indicates that the estimate of damages to our underground infrastructure ranges between 600,000 and 750,000 damages per year. Of the damage reports available for analysis, more than 40 percent of the damages were associated with work where a call to the one-call center had not occurred. The number one work activity being performed at the time of the damage was landscaping. More statistics and charts are available on our website. We encourage all companies to input their confidential data to this free system in order that these companies and the industry as a whole can determine what our problems are and what we may do to fix these problems.

Secondly, best practices on compliance and enforcement in the distribution integrity management report. In August 1999, the 161 experts who developed the best practices unanimously agreed that an effective compliance and enforcement program at the State level was required to reduce the incidences of damage to the infrastructure.

There are a number of States with effective enforcement programs, including Minnesota, Virginia, New Hampshire, Maine, Connecticut, New Jersey, Georgia, Arizona, Massachusetts, and others. That idea holds true today. When examining gas distribution damage data available to the distribution integrity management program, the committee responsible for this analysis, at the rate of damages per thousand tickets, in Virginia and Minnesota, two States with effective enforcement programs, was lower than two comparable States with no enforcement programs. Virginia had 2.25 gas distribution damages per thousand tickets in 2005. Minnesota had 2.98 damages per thousand tickets, a 60-percent decrease in their past 10 years. The DIMP results team analyzed and provided statistics on two similar States without enforcement programs. One State has averaged approximately 6.7 damages per thousand tickets over the past 5 years, while the other State, at 6.9 damages per thousand tickets also for the past 5 years.

Though operationally different, the Virginia program and Minnesota program are similar in that every gas or liquid damage is investigated and, when appropriate, the company responsible for the damage is fined.

Earlier I stated that more than 40 percent of damages in the country, no call was made to the one-call center. In Virginia, that number is between 13 and 18 percent only. They are virtually all homeowners. Few are professional excavators. They call the center. Additionally, 99 percent of locates are done on time both in Minnesota and Virginia. The industry has responded positively to the enforcement program. Compliance and enforcement has resulted in a trusting, professional industry where all stakeholders know their roles and complete their tasks accordingly.

The third item, three-digit dialing. The Pipeline Safety Improvement Act of 2002 included a provision for the establishment of a three-digit nationwide toll-free telephone number system to be used by State one-call notification systems. We congratulate and thank this committee and former Congressman Chris John for introducing and sponsoring three-digit dialing as a provision of the Pipeline Safety Improvement Act. The one-call centers across the country have been working with the various telecoms to coordinate implementation of 811 in order to completely roll out the system in early 2007. We expect an increase in the more than 20 million annual calls received by the Nation's 62 one-call centers. We believe that a coordinated public awareness campaign should help reduce the 40 percent of damages where no call was made to the one-call center.

While our one-call center committee has been working with technical aspects of the conversion, our education team has been tasked with coordinating the development of a logo and tagline as well as selecting a firm to develop a public awareness campaign. This logo and tagline was released last month, and there it is up there. I am sure that you can identify that the CGA is very proud of this logo, and we expect you are going to see this logo on a regular basis beginning early in 2007.

Requests. The CGA requests the committee consider the following in their deliberations. One, extending the annual cooperative grant to the CGA for the duration of the reauthorization. This money is targeted to specific programs. We continue to require technology enhancements in our efforts to expand the use of and effectiveness of the DIRT tool as well as other software/hardware upgrades. We would also request that the committee consider providing an additional $1 million in 2007 to enable the CGA to extend its nationwide public awareness of 811 as it cuts over early next year. Secondly, as with the DIMP ommittee report to the CGA, we would request that this committee develop a method to assist the State governments in implementing a compliance and enforcement program consistent with their one-call laws. The CGA believes that effective compliance and enforcement of State laws and the implementation of 811 and an industry-wide volunteer participation in submitting data to our DIRT tool will help reduce injuries, fatalities, and damages to our industry.

The Common Ground Alliance is a true member-driven organization, and the 300 committee members from the 15 stakeholder groups work together to determine direction and problem solve, making the CGA a really unique forum. Their efforts and the financial support of their companies are what make the CGA a success. The CGA is extremely grateful for the support of Ms. Stacey Gerard of PHMSA and her great staff, who can never do enough for the CGA.

Thank you.

[The prepared statement of Bob Kipp follows:]

PREPARED STATEMENT OF BOB KIPP, PRESIDENT, COMMON GROUND ALLIANCE

SUMMARY

The Common Ground Alliance is a nonprofit organization dedicated to shared responsibility in the damage prevention of underground facilities. The CGA works to prevent damage to the underground infrastructure by:

- fostering a sense of shared responsibility for the protection of underground facilities;
- supporting research;
- developing and conducting public awareness and education programs;
- identifying and disseminating the stakeholder best practices such as those embodied in the Common Ground Study; and
- Serving as a clearinghouse for damage data collection, analysis and dissemination.

Since meeting with this committee in July 2004, the CGA has grown to more than 1200 individuals representing 15 stakeholder groups and 130 member organizations. In addition, there are some 1000 or so members involved in our 43 regional partner groups.

Each of the 15 stakeholder groups has one seat on the CGA board of directors, regardless of membership representation or financial participation. CGA members populate the organization's six working committees: Best Practices, Research & Development, Educational Programs & Marketing, Membership, & Communications Committee, Data Reporting & Evaluation, , and the One Call Center Education Committee.

Key initiatives described in the following testimony include:

A. Resolution of 9 NTSB recommendations forwarded to the CGA for resolution by the Office of Pipeline Safety;
B. Rollout of 43 regional CGA's throughout the country;
C. Identification of the "Virginia Pilot Project for Locating Technology";
D. Implementation of the CGA Damage Information Reporting Tool (DIRT);
E. Review of CGA Best Practices and their relation to PHMSA's Distribution Integrity Management Program;
F. Review of D.I.M.P. results, the Virginia and Minnesota Enforcement Programs and the use of the CGA D.I.R.T. tool in support of these programs;
G. Rollout of "811", the 3 digit number to access one call centers across the country

Testimony of Robert Kipp, Executive Director of the Common Ground Alliance, to the Subcommittee on Energy and Air Quality

Good afternoon, Mr. Chairman and members of the Committee. My name is Robert Kipp and I am the President of the Common Ground Alliance (CGA). I am pleased to appear before you today to represent the CGA.

Background:

The Common Ground Alliance is a nonprofit organization dedicated to shared responsibility in the damage prevention of underground facilities. The Common Ground Alliance was created on September 19, 2000, at the completion of the "Common Ground Study of One-Call Systems and Damage Prevention Best Practices." This landmark study, sponsored by the U.S. Department of Transportation Office of Pipeline Safety, was completed in 1999 by 161 experts from the damage prevention stakeholder community.

The "Common Ground Study" began with a public meeting in Arlington, VA in August 1998. The study was prepared in accordance with, and at the direction and authorization of the Transport Equity Act for the 21st Century signed into law June 9, 1998 that authorized the Department of Transportation to undertake a study of damage prevention practices associated with existing one-call notification systems. Participants in the study represented the following stakeholder groups: oil; gas; telecommunications; railroads; utilities; cable TV; one-call systems and centers; excavation; locators; equipment manufacturers; design engineers; regulators; federal, state, and local government. The Common Ground Study concluded on June 30, 1999 with the publication of the "Common Ground Study of One-Call Systems and Damage Prevention Best Practices."

At the conclusion of the study, the Damage Prevention Path Forward initiative led to the development of the nonprofit organization now recognized as the Common Ground Alliance (CGA). The CGA's first board of directors' meeting was held September 19, 2000. Building on the spirit of shared responsibility resulting from the Common Ground Study, the purpose of the CGA is to ensure public safety, environmental protection, and the integrity of services by promoting effective damage prevention practices.

The CGA now counts more than 1,200 individuals representing 15 stakeholder groups and over 130 member organizations. Each of the 15 stakeholder groups has one seat on the CGA Board of Directors, regardless of membership representation or financial participation. CGA members populate the organization's six working committees: Best Practices, Research & Development, Educational Programs Marketing, Membership, & Communications, Data Reporting & Evaluation, the One Call Center Education Committee, and the Regional Partners Committee.

WORKING COMMITTEES

The CGA working committee guidelines include:

- All stakeholders are welcomed and encouraged to participate in the Committees' work efforts.
- Committee members represent the knowledge, concerns and interests of their constituents.
- A "primary" member is identified within each Committee for each particular stakeholder group as the spokesperson for consensus decisions.

The Common Ground Alliance is managed by the association's Board of Directors. Currently, each director on the Board represents one of the fifteen CGA stakeholder categories. The Directors are elected by the CGA members within their respective stakeholder group, and represent the stakeholder group at approximately 5 meetings and to 3 – 6 teleconferences per year. Following are the names of the directors and the stakeholder group they represent.

Excavator…………………………Fred Cripps, Distribution Construction Company
State Regulator……………………………….. Glynn Blanton, Tennessee Reg. Authority
Insurance……………………………...Raymond Pyrcz, Aegis Insurance Service, Inc.
Railroad…………………………Bob VanderClute, Association of American Railroads
Oil (vice chair)………………………………..Timothy Felt, Explorer Pipeline Company
Locators…………………………………………………......Jamal Masumi, Utiliquest LLC
Public Works………………………………………………......Mark Macy, City of Nashville
One Call…………………….....JD Maniscalco, Utility Notification Center of Colorado
Equipment Mfg………………………………………......Scott Pollman, Subsite Electronics
Gas.(chair)……………………………………………......Paul Preketes, Consumers Energy
Engineering……………………………………………………......Bill Johns, SPEC Services
Road Builder…(treasurer)………………………………....Vic Weston, Tri-State Boring
Electric……………………………………………………….....Alan Yonkman, Detroit Edison
Telecomm…………………………………………………………......John Thomas, Sprint
Emergency Services……………….Jim Narva, Dep. of Fire Protection/Electrical Safety, State of Wyoming

A. Best Practices Committee

To promote damage prevention, it is important that all stakeholders implement the damage prevention Best Practices currently identified in the Common Ground Study Report, as applicable to each stakeholder group. The Best Practices Committee focuses on identifying those Best Practices that are appropriate for each stakeholder group, gauging current levels of implementation and use of those Best Practices, and encouraging and promoting increased implementation of the Best Practices.

B. Research and Development Committee

The Research & Development Committee's primary role is to promote damage prevention research and development and serve as a clearing house for gathering and disseminating information on new damage prevention technologies and practices. The Research and Development Committee seeks to identify new technologies and existing technologies that can be adapted to damage prevention.

C. Educational Programs and Marketing, Membership, & Communication Committee

The Committee develops and communicates public stakeholder awareness and educational programs. These programs and products focus on the best practices and the theme of damage prevention. The Committee looks at existing damage prevention education programs to identify opportunities where the CGA can have significant impact in furthering the reach and effectiveness of those programs and the Committee develops new educational messages and items.

The Committee pursues opportunities where it can best promote the organization to increase sponsorship and membership. The Committee is also dedicated to the adoption of the Best Practices and promotion of damage prevention at the local level, and the committee has developed the CGA's Regional Partner Program to further this effort.

D. Data Reporting and Evaluation Committee

The Data Reporting & Evaluation Committee looks at currently available damage data, the gaps where additional data reporting and evaluation is needed, and how such data for various underground infrastructure components can best be gathered and published. Reporting and evaluation of damage data is important to: measure effectiveness of damage prevention groups; develop programs and actions that can effectively address root causes of damages; assess the risks and benefits of different damage prevention practices being implemented by various stakeholders; and assess the need for and benefits of education and training programs.

E. One Call Center Education Committee

The purpose of One-Call Systems International (OCSI) is to promote facility damage prevention and infrastructure protection through education, guidance and assistance to one call centers internationally. They are also responsible for coordination of the nationwide rollout of "811".

F. Regional Partner Committee

The CGA recognizes that existing regional damage prevention groups have invaluable knowledge and experience, and these groups continue to make great strides in preventing excavation damage to America's infrastructure. The CGA also recognizes that some areas of the country currently have no regional damage prevention programs. Through the CGA Regional Partner Program, the CGA partners with existing local, regional, and state damage prevention programs that have an objective of promoting communication among all stakeholders about damage prevention Best Practices.

ACTIVITIES

A. NTSB RECOMMENDATIONS

In July of 2001, the Office of Pipeline safety requested CGA's assistance in resolving and responding to a number of outstanding National Transportation Safety Board recommendations. In the past 5 years the CGA contributed to the closing of 9 NTSB recommendations. A tenth recommendation was directed to the CGA in 2005 and is currently in committee. The first nine recommendations were deemed "Closed – Acceptable" by the NTSB.

B. REGIONAL PARTNER PROGRAM

Since beginning this program, some 43 regional partners have been accepted into the CGA. These partners cover groups operating across most of the United States and parts of Canada. Their membership totals more than 1000 individuals involved in our industry across this country. The Regional Partners are:

Alberta Utility Coordination Council
Allegheny/Kiski Valley Coord. Committee
Blue Stakes of Utah Utility Notification Center
British Columbia Common Ground Alliance
California Regional Common Ground Alliance
Central Texas Damage Prevention Council
Delaware Valley Damage Prevention Council
Denver Metropolitan DPC
Dig Safely New York Regional DPC
El Paso County Damage Prevention Council
Georgia Utilities Coordinating Council
Greater Columbus Damage Prevention Council
Greater Toledo Underground DPC
Greater Youngstown Underground DPC
Indiana Underground Plant Protection Service
Johnstown Area Public Service Committee
Nevada Regional CGA Partnership
New Jersey Common Ground Alliance
New Mexico Regional CGA
North Carolina Regional CGA
Northeast Illinois Damage Prevention Council
Northwest Region Common Ground Alliance
Oklahoma One-Call System
Ontario Region Common Ground Alliance
Pittsburgh Public Service Committee
Public Service Committee Indiana County
Quebec Regional CGA
SE North Dakota – Utility Partnership
Southwest Ohio Utility Safety Council
Tennessee Damage Prevention Committee
Texas Common Ground Committee
Utilities Council of Northern Ohio

Miami Valley Utility Damage Prevention Council
Michigan Damage Prevention Board
Minnesota Utility Alliance
Miss Utility of West Virginia
Mississippi One-Call System, Inc.
Missouri Common Ground
Utility Service Protection Center, Delmarva
Virginia Utility Protection Service, Inc.
Western Region Common Ground Alliance
Wisconsin Underground Contractors Assoc.
Wyoming Regional CGA Partnership

C. VIRGINIA'S PILOT PROGRAM FOR ONE – CALL LOCATION TECHNOLOGY

In 2005 a number of representatives from various industry groups, government, and associations met to put together a framework to develop a trial program in Virginia. The purpose of this pilot project will be to research and implement new and existing technologies that appear to have great potential to significantly enhance the communication of accurate information among excavators, one-call centers, underground facility operators and facility locators.

In ensuing meetings the participants list has grown, the business case developed, timelines developed, and processes set to begin the trial in the next few months. It is expected that the results will be known in a year. As can be seen from the list of participants that follows, the industry is poised to make this trial the high water mark for the industry in terms of technology use and benefits of same.

Participants List

Participant	Organization
Johnnie Barr	NUCA (Ward & Stancil, Inc.)
Terry Boss	INGAA
Scott Brown	Washington Gas
Carl Brumfield	Utiliquest
Corey Bufi	GE
Rodney Cope	GE
Kris Countryman	Verizon
Kim Cranmer	Verizon
David Doyle	ProMark
Quintin Frazier	Plantation/Kinder Morgan
Catherine Graichen	GE
Harvey Haines	PRCI
Wayne Hamilton	Plantation/Kinder Morgan
Roger Haycraft	Texas Gas Transmission/PRCI
Christina Head	Colonial Pipeline
Sandra Holmes	AZ Blue Stake/CGA R&D Committee
Blaine Keener	PHMSA
Bob Kipp	CGA (conference line)
Joe Kucera	Angler Construction Co. / HCCA
Cedric Kline	Colonial Pipeline
Jamal Masumi	Utiliquest
Stu Megaw	AGC
Dan Paterson	Williams

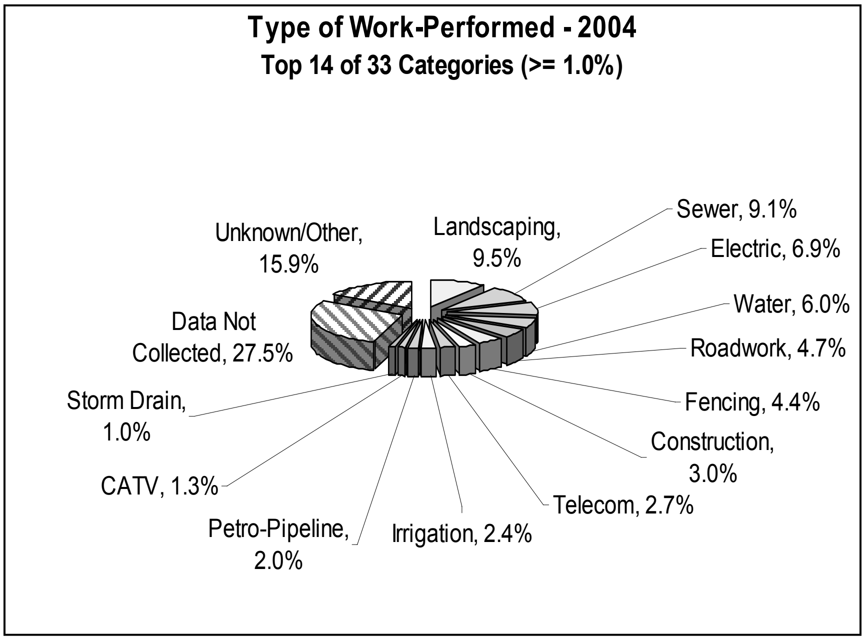
Rick Pevarski	Virginia UPS
Dave Price	Virginia UPS
Massoud Tahamtani	Virginia SCC
George Tenley	PRCI
Dwayne Teschendorf	Duke
Scott Thetford	GE
Scott Tolliver	Verizon
Isaac Weathers	Georgia Utilities Protection Center
John West	VUPS Board
Jeff Wiese	PHMSA
Herb Wilhite	Cycla Corp.

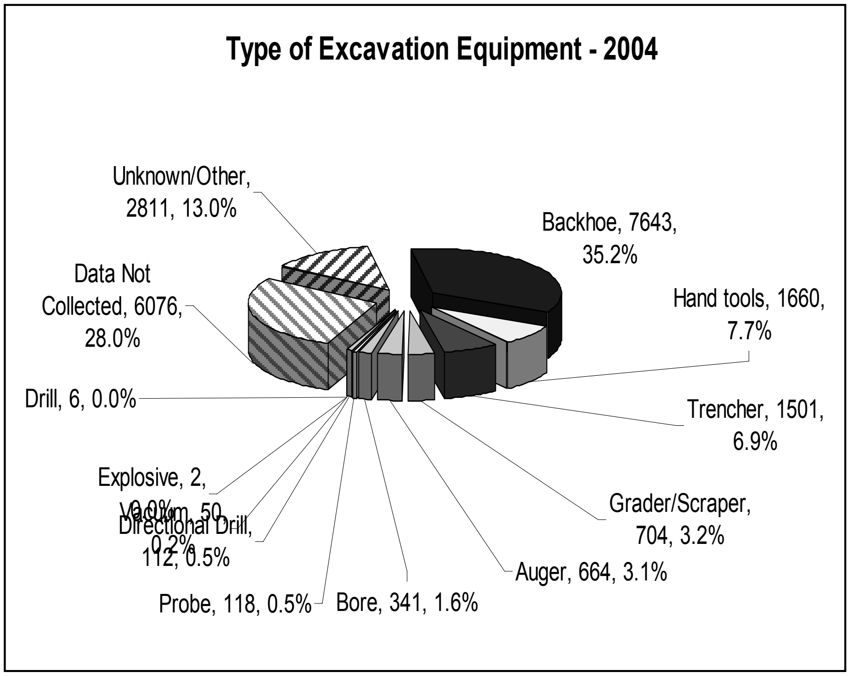
D. DAMAGE INFORMATION REPORTING TOOL

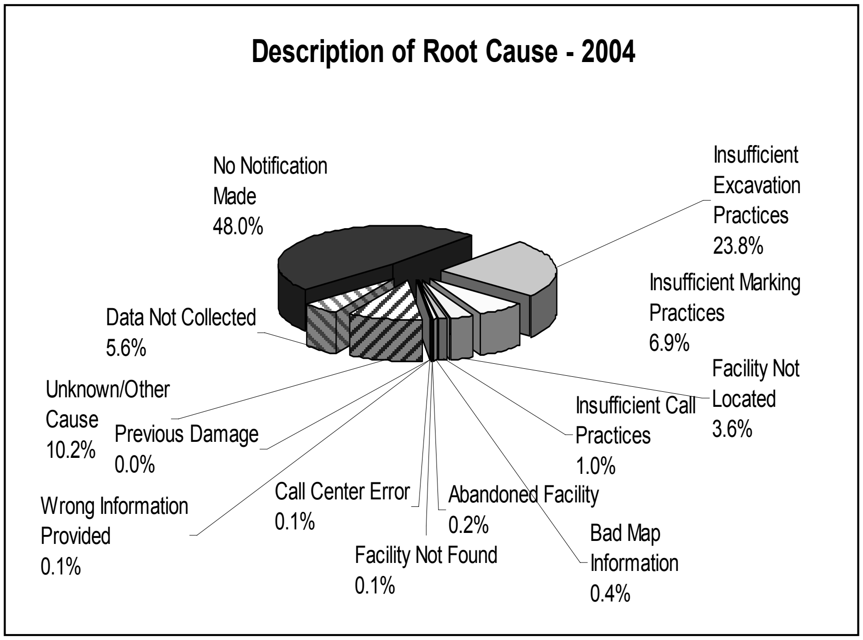
The primary purpose in collecting underground facility damage data is to analyze data, to learn Why events occur, and how actions by industry can prevent them in the future; thereby, ensuring the safety and protection of people and the infrastructure. Data collection will allow the CGA to identify root causes, perform trend analysis, and help educate all stakeholders so that damages can be reduced through effective practices and procedures.

The CGA's purpose is to reduce underground facility damage, which threatens the public's safety and costs billions of dollars each year. In order to better understand where, how and why these damages are occurring, we require accurate and comprehensive data from all stakeholders. Late last year the CGA published its first report on damage data.

A sample of the charts and graphs included in this report follows.







It should be noted that the estimate of damages to our underground infrastructure ranges between 600, 000 and 750,000 damages per year. Of the damage reports available for analysis, more than 40% of the damages were associated with work where a call to the 1 call center had NOT occurred.

The CGA is hopeful that this system will be used by all stakeholders on a nationwide basis, in order to help the industry gather the statistical data that will enable us to develop plans to help us reduce the approximately 400,000 damages nationwide.

A number of state regulators are currently considering gathering damage data within their jurisdictions. We hope that those states considering adopting some of the practices in Colorado, Connecticut and other states, consider utilizing the CGA system in order to have one uniform, actionable national database.

The CGA believes that a strong state compliance and enforcement program combined with strong damage data analysis will assist in reducing damages.

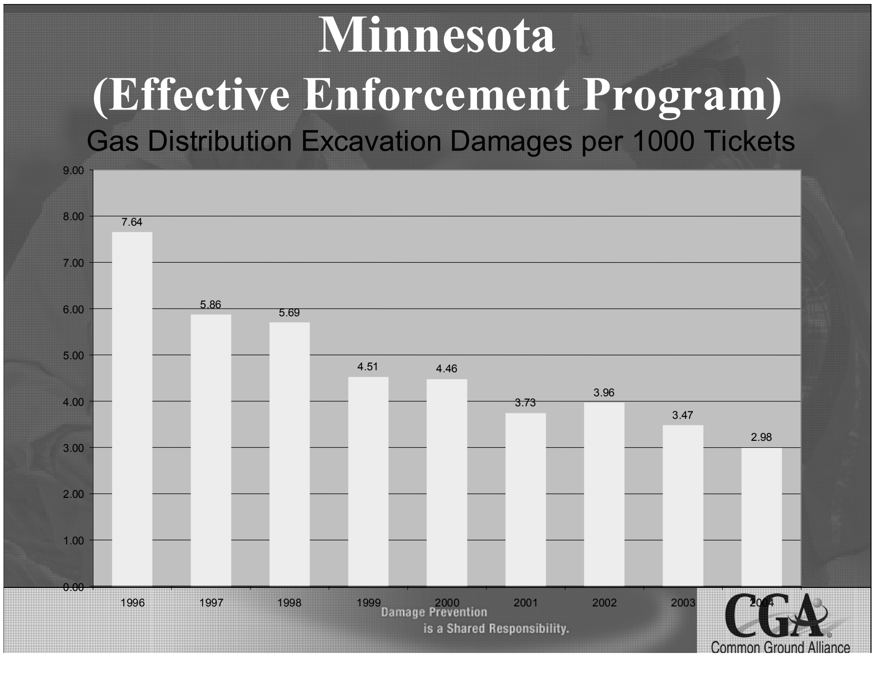
E. BEST PRACTICES – COMPLIANCE AND ENFORCEMENT

In August 1999, the 161 experts who developed the Best Practices unanimously agreed that an effective Compliance and Enforcement program at state level was required to reduce the incidences of damage to the infrastructure.

These practices are contained in the Common Ground Alliance's Best Practices Version 3.0

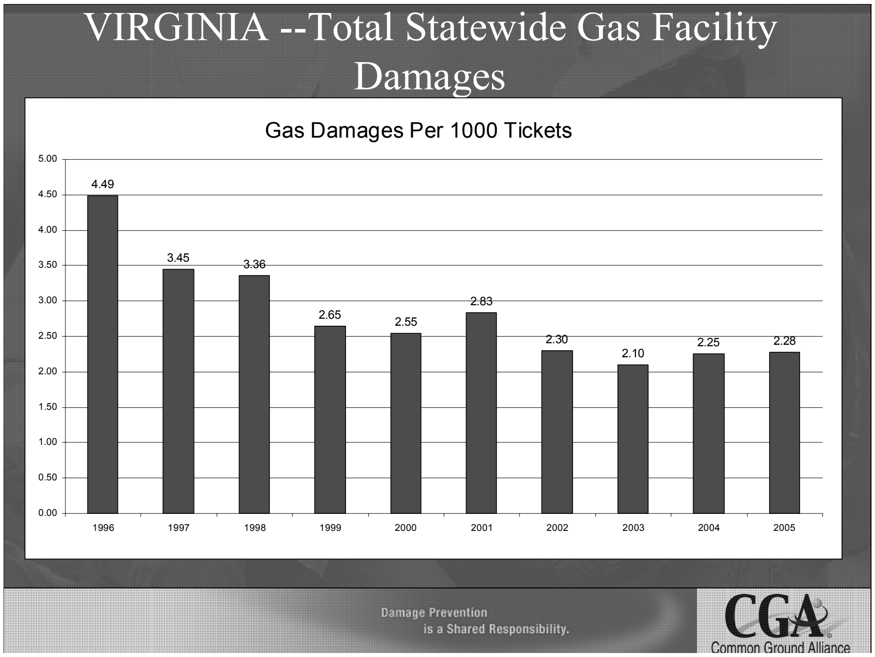
There are a number of states with effective enforcement programs including Minnesota, Virginia, New Hampshire, Maine, Connecticut, New Jersey, Arizona, Massachusetts, Virginia, and others.

That idea holds true today. When examining gas distribution damage data available to the D.I.M.P. committee responsible for analysis, the rate of damages in Virginia and Minnesota, 2 states with effective enforcement programs, the rate of damages per 1000 tickets was far superior to 2 comparable states with no enforcement programs. This can be seen in the following charts:



Minnesota
(Effective Enforcement Program)

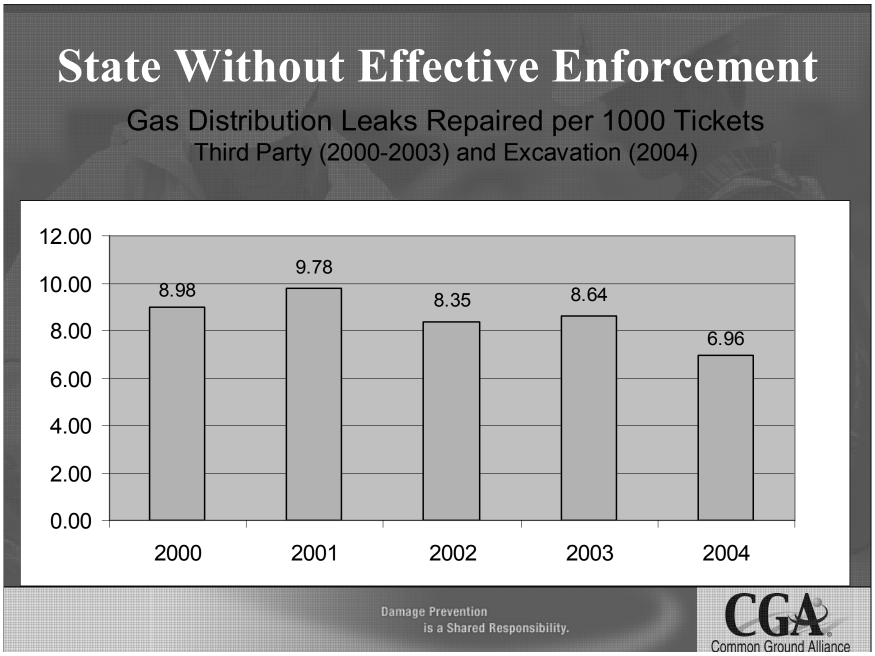
Gas Distribution Excavation Damages per 1000 Tickets



VIRGINIA --Total Statewide Gas Facility Damages

Damage Prevention is a Shared Responsibility.

CGA Common Ground Alliance

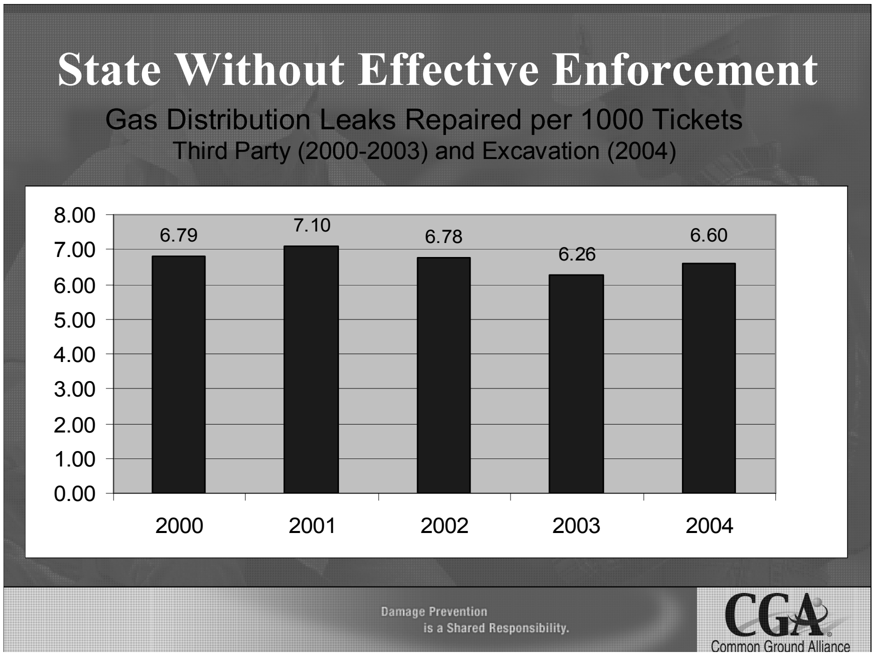


State Without Effective Enforcement

Gas Distribution Leaks Repaired per 1000 Tickets
Third Party (2000-2003) and Excavation (2004)

Damage Prevention is a Shared Responsibility.

CGA Common Ground Alliance



State Without Effective Enforcement

Gas Distribution Leaks Repaired per 1000 Tickets

Third Party (2000-2003) and Excavation (2004)

Damage Prevention is a Shared Responsibility.

CGA Common Ground Alliance

These slides are from the Distribution Integrity Management Program Report available on PHMSA's website.

F. D.I.M.P. RESULTS
MINNESOTA AND VIRGINIA ENFORCEMENT PROGRAM

Though operationally different the Virginia Program under Massoud Tahamtani and the Minnesota Program under Charles Kenow and Mike McGrath are similar in that every gas or liquid damage is investigated, and when appropriate, the company responsible for the damage is fined.

Their damage rates are very low when compared to most states without enforcement programs.

Earlier, I stated that in more than 40% of damages in the country, no call was made to the 1 call center. In Virginia, the number is between 13% and 18%. They are virtually all homeowners. Additionally, 99.0% of locates are done on time in both Minnesota and Virginia. The industry has responded positively to the enforcement program.

The professional excavator knows that when he calls, the locate will be done on time. The owner/operator hires sufficient well-trained locators to do the job on an accurate and timely basis. Marks are adhered to, injuries are reduced, standown time is reduced, damages are reduced and both the public and industry benefit from a professional work process.

One of the key findings in the D.I.M.P. report is that the Federal Government finds the means to encourage State Governments to develop and implement a Compliance and Enforcement Program. The CGA has worked closely with Stacey Gerard and her staff in many of the initiatives described in this paper and has found PHMSA to be very supportive of all stakeholders involved in this industry and the CGA's consensus process.

In many ways the D.I.M.P. report to PHMSA under the chairmanship of Glynn Blanton of Tennessee mirrors many of the findings of the original best practices report of 1999.

The CGA supports this concept and has promoted a State Compliance and Enforcement Program since the publication of the Best Practices in 1999.

G. 3-DIGIT-DIALING

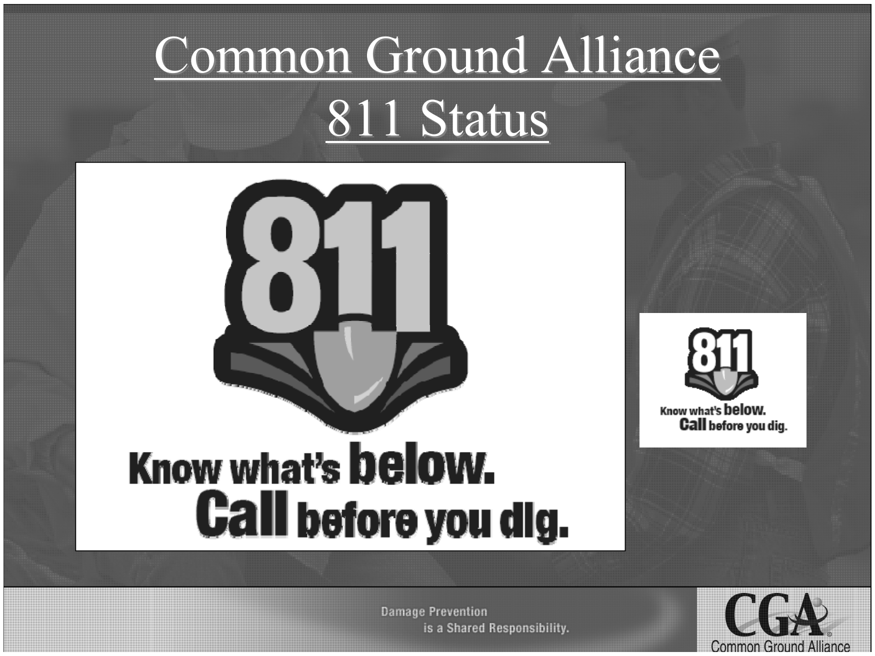
On December 17, 2002, President George W. Bush signed into law the "Pipeline Safety Improvement act of 2002". Included in this Act was the following provision:

"Within 1 year after the date of the enactment of this Act, the Secretary of Transportation shall, in conjunction with the Federal Communications Commission, facility operators, excavators, and one-call notification system operators, provide for the establishment of a 3-digit nationwide toll-free telephone number system to be used by State one-call notification systems."

We congratulate and thank this committee and former congressman Chris John for introducing and sponsoring 3digit dialing as a provision to the "Pipeline Safety Improvement Act of 2002." We congratulate the FCC commissioners on their unanimous support of this endeavor. The One Call Centers across the country have been working with the various telecoms to coordinate implementation of "811" in order to completely rollout the system in early 2007. We expect an increase in the more than 20 million annual calls received by the nation's 62 one call centers. We believe that a coordinated public awareness campaign should help reduce the 40% of damages where no call was made to the 1 call center.

Bill Kiger and Sandy Holmes our One Call co-chairs have worked with the telecoms the past few months to ensure a seamless transition to "811". We congratulate Verizon Wireless and the numerous rural and community telephone companies who have completed the translation work in their switches at no cost to the one call centers. Bill Kiger is currently negotiating what we hope will be a similar arrangement with Cingular. At this time we are not aware of any issues which will prevent a complete transition to the "811" number early next year.

While our One Call Center Committee have been working with the technical aspects of the conversion Tom Shimon and Dan Meiners CGA's 811 task team co-chairs have successfully contracted to Celeritas and Krysanne Kerr the task of coordinating the development of a logo and tagline as well as as selecting a firm to develop a public awareness campaign. Below is the logo and tagline developed by RBMM of Dallas.



Common Ground Alliance
811 Status

811
Know what's below.
Call before you dig.

811
Know what's below.
Call before you dig.

Damage Prevention
is a Shared Responsibility.

CGA
Common Ground Alliance

The CGA is proud of the new 811 logo and tagline and looks forward to nationwide use of this mark to announce 811 implementation.

CLOSING

The Common Ground Alliance is a true member-driven organization. Members from the 15 stakeholder groups work together to determine direction and problem-solve, making the CGA a truly unique forum. The 300 or so committee members check egos at the door and work together to develop consensus decisions. Their efforts and the financial support of their companies are what make the CGA the success it has become.

The CGA would not exist without the financial and logistical support of Ms. Stacey Gerard of PHMSA and her great staff led by Jeff Wiese who can never do enough for the CGA. The CATS folks of PHMSA led by Blaine Keener have been a wonderful addition to the damage prevention efforts.

Lastly our sponsors; it is the 31 companies that sponsor the CGA that make a difference. There are many other companies in this country reaping substantial benefits from the CGA activities without contributing to its success. To those companies, it’s time to get on board.

Thank you for the opportunity to provide you with this testimony.

MR. HALL. Thank you.

We will ask some questions, but I will ask unanimous consent that you be allowed to respond to questions that members submit to you in writing. In their absence here, they are entitled to that. And if you could, be as timely as you can with giving us a return on it, so we can get it into the record for everybody else to read.

I am going to start out and ask a question.

Most of you expressed some concerns regarding the 7-year requirement for reassessments. And as I understand the way the law is currently written, the 7-year interval only applies to those segments of pipes that required repair based on information gained from the baseline assessment. Is that your understanding? And if this is true, what is the overlap concern?

MR. MOHN. With all due respect, Mr. Chairman, the 7-year reassessment applies to all of our pipelines that are in high-consequence areas. So let me try to describe it this way. By the end of 2012, we will have done our baseline assessment on all of the HCAs. Then we are required to reassess all of those HCAs, each one of them within a 7-year period. Our concern is that the way the law is written, it requires that we start the reassessment period in 2010, prior to completion of establishment of the baseline. And that would mean that we have to inspect not just the 10 percent a year that we need to do to get the baseline, but we also have to assess about 14 percent a year, or 100 divided by 7, in order to hit the reassessment period, which gives us a total annual workload of somewhere in the range of 25 percent.

MR. HALL. Anyone else want to comment on that?

Yes, Ms. Epstein?

MS. EPSTEIN. That is an accurate characterization of what the law requires. What the public interest community believes is that potentially that would be an appropriate workload, because some of the tests would have been done, in fact, quite a long time before, and so reassessment may be appropriate. We recognize there is a waiver provision in the pipeline safety statute at this time that if there is a problem, if there is some reason why a particular company or a particular geographic location cannot meet that timeframe, then PHMSA would be able to grant a waiver.

So you know, we are, as everyone else is, anxious to hear what the Government Accountability Office has to say on this matter, but we do think, you know, we are not way off where we need to be right now, and potentially--

MR. HALL. Do you want to change it or lessen it or extend it?

MS. EPSTEIN. At this point, I think we should wait. We should maintain the current statutory requirements, unless there is compelling evidence from the GAO or from the industry in a few years that things need to be changed.

MR. HALL. Mr. Kipp, do you have any comment on that?

MR. KIPP. No comment on that.

MR. HALL. Anyone else?

The Chair recognizes the gentleman from Virginia.

MR. BOUCHER. Well, thank you, Mr. Chairman, and I want to express appreciation to our witnesses for taking part in our hearing today, also.

Mr. Bender, let me begin with you. I appreciate you preparing that demonstration of the nine points that have resulted in success in preventing excavation damage and the places where those nine principles are in operation. I think Virginia first and then perhaps rapidly followed by Minnesota are the key examples around the country.

I asked a question on the previous panel about whether there is something we could do at the Federal level to encourage more States to adopt similar principles. And I gather that among the principles, enforcement is fundamentally important. And there has to be an enforcement program for the excavation damage to be prevented. But what do you think, and what would you recommend, that we do? We are going to be reauthorizing the 2002 statute. It creates the legislative opportunity to make a variety of changes. And within that opportunity, what would you suggest that we do in order to encourage more States to do what Virginia and Minnesota have done so successfully? And the range of opportunities might be from simply requiring the nine-point program in each of those States to some less regulatory and more incentive-based approach. So what is your association's suggestion to us?

MR. BENDER. Thank you, Congressman.

The main thing, I think, that can be done and should be done is to introduce legislation with these nine tenets of damage prevention. Within these tenets is the capability to improve communication and to improve enforcement. Currently, a lot of enforcement is done by the State attorney or city attorney, and they are more involved with criminal activity. So consequently, many times enforcement is just lacking. The people who really should be enforcing this are the people who are responsible for enforcement of the regulation: the State safety people, the State engineering people associated with the regulatory responsibility. Money is important. I know nobody likes to hear that Federal dollars are needed, but they are, because without those dollars, there are people that exist today to do the functions within the State organizations that need to be done. This approach advocates a carrot and a stick approach. The carrot is training. And that also involves, if I may, what do you do when you strike gas and there is throwing gas and there is a danger. People, excavators, need to know and need to be trained as to who they call and when they call and what they explicitly do. That is important. That is part of this program. That training costs money.

Recognition is important. Recognition of people who are doing very well through various means. But again, that requires money, and this group of stakeholders that got together, that PHMSA, to their credit, assembled and said, “Let us collaboratively come up with some solutions.” You know, basically, they are saying if there is one thing we want to do, if there is one thing you want to spend your money on to improve public safety, it is this.

MR. BOUCHER. Do you know how much money we should appropriate on an annual basis to the States in order to carry this program forward effectively?

MR. BENDER. Unfortunately, at this point, I do not, but I am sure that we, along with the other stakeholders, would be happy to work with the committee to determine that.

MR. BOUCHER. Oh, well, that is helpful. Thank you, Mr. Bender. I have another question of you, but before I come to that, let me ask Mr. Mohn if he is in general agreement with what Mr. Bender has just said in terms of what Congress ought to do to promote excavation prevention.

MR. MOHN. We are. In all likelihood, the funds to support the States’ enhancement of their programs will come from user fees, and while we support the necessity for some funding or a reallocation of funding within States, we would certainly urge an examination of the current dollars that are flowing to States to ensure that there aren’t dollars in those, based upon the experience of Virginia, where they found a way to fund the program without incremental dollars. The idea of incentivizing States, either by an additional grant or perhaps not as much funding as they would otherwise have gained for introducing a program that would incorporate these nine points, both work for us, and as in Mr. Bender’s case, we would love to work with the committee and your staff to find a way to make this a reality.

MR. BOUCHER. Well, thank you. We will accept that offer.

Mr. Kipp, would you care to comment on this question?

MR. KIPP. Yes, if I could, if this mic works. Great.

I think it is important for the committee to also understand that all stakeholders support this. It is not just a gas initiative, an oil initiative, or a PHMSA initiative. And part of the DIMP committee included representatives from the National Utility Contractors Association, from the Association of General Contractors. Our best practices include members from those two groups. In the audience here today, there are members from the AGC and NUCA, and they are here to listen to the goings-on. They are active participants in everything we do, and they want to be part of the solution.

At the end of the day, it is typically the people in those two industries that get hurt. Those trench accidents and explosions, if it is not homeowners, it is typically people working on equipment, and it is often the excavators. So there is a lot for them at stake here, and they support this 100 percent.

MR. BOUCHER. All right. Thank you.

Ms. Epstein, I saw you reaching for the microphone a moment ago. No? All right. That is fine.

Mr. Bender, a second question for you. You have heard Ms. Gerard testify that she is moving forward with a final distribution integrity rule. Are you satisfied with the progress that is being made on that? Would you recommend to us that we insert some kind of statutory deadline by which that rule has to be published? Or do you think the progress being made currently is satisfactory?

MR. BENDER. I certainly think the progress in developing the regulation is moving satisfactorily. We would support a deadline that you described. We have been working with a group of stakeholders, including PHMSA, to develop a recommended schedule, if you will, that will meet the requirements and provide a great program in an expeditious manner.

So our short answer is yes.

MR. BOUCHER. Okay.

Mr. Mohn, one question for you. I know that you heard our earlier discussion today with respect to the waiver authority that Ms. Gerard has with regard to the 7-year required re-inspections. And if problems arise, she is there to consider possible relief. So I suppose my question to you is I know your association has been recommending that we have a statutory change with regard to the 7-year re-inspections to address the potential that there might be some supply disruption involving this overlap between the 10-year inspection and the 7-year inspection in order to guard against the possibility that there might be a shortage of inspectors, because you have got a lot of inspections taking place at once. But that is precisely what the waiver authority is designed to address. So why is your association not comforted by the presence of the waiver authority? Why are you, instead, asking for a statutory relief?

MR. MOHN. That is a good question.

I would sum it this way. PHMSA and its predecessor, OPS, have had waiver authority from the time that I have been in the industry; I would expect maybe since the statute was originally passed. And we have rarely requested waivers or rarely put that process into place, because generally the regulations are things that we should follow.

Our concern is the uncertainty associated with the granting of waivers and the potential need on an operator-by-operator basis to request waivers that might even be regionally specific would not yield the certainty that we would like to have as to the way we are going to manage resources in that 3-year period.

I think your testimony from GAO earlier today summed the issue up very, very succinctly. We are looking to have to increase not just people, but smart pig resources by over twice for a 3-year period, and to suggest that somehow these companies who are in the business to make money are going to ramp up for 3 years without a commitment or an expectation that the equipment will be needed in subsequent years is a stretch.

Her comment also about direct assessment being a new technology that is only ramping up now as opposed to the more mature smart pig technology, I think, is quite relevant.

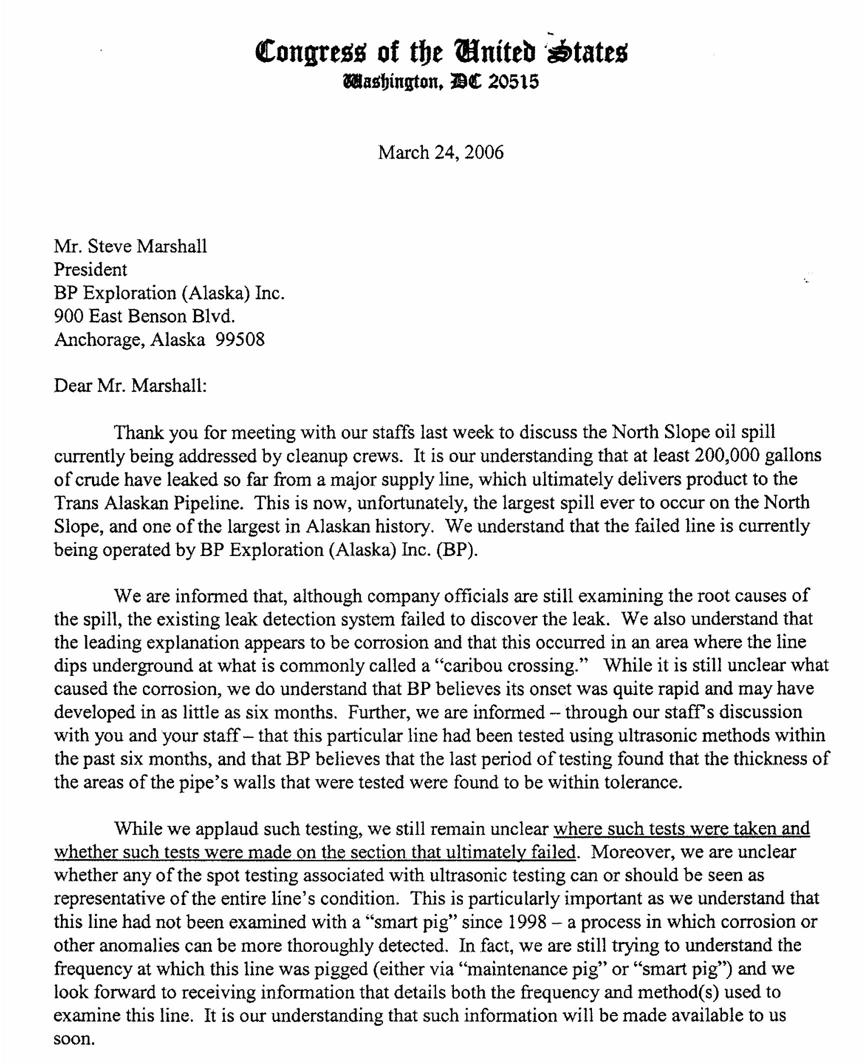
So in summary, we would like the certainty of the way we are going to plan and manage our resources within that 3-year period as opposed to the uncertainty of this path related to waivers, again recognizing that we could literally have tens if not hundreds of waivers hitting PHMSA.

MR. BOUCHER. Well, thank you, Mr. Mohn. You have expressed your association's position very clearly, and we appreciate you sharing that with us.

Mr. Chairman, I have completed my questions. I have a unanimous consent request, and that is that we insert in the record some correspondence that Ranking Member Dingell has had on several of the issues that we have been discussing here this morning.

MR. HALL. I have been advised that our staff has looked at it and it is acceptable. Without objection, I hear none, it will be inserted.

[The information follows:]



Congreſs of the United States
Waſhington, DC 20515

March 24, 2006

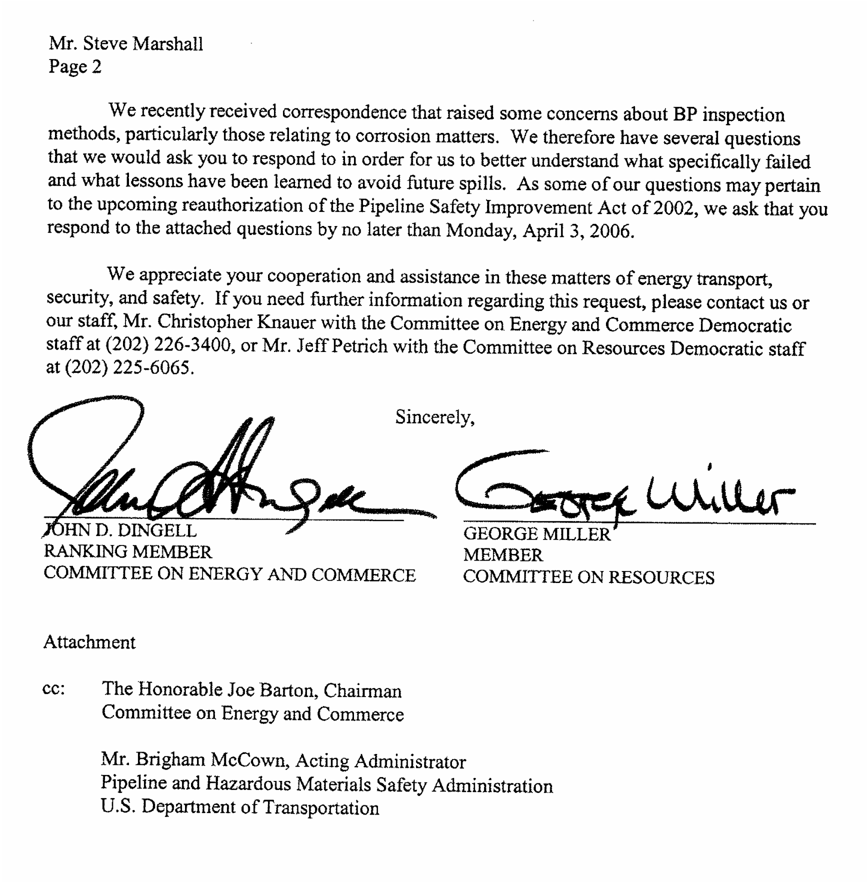
Mr. Steve Marshall
President
BP Exploration (Alaska) Inc.
900 East Benson Blvd.
Anchorage, Alaska 99508

Dear Mr. Marshall:

Thank you for meeting with our staffs last week to discuss the North Slope oil spill currently being addressed by cleanup crews. It is our understanding that at least 200,000 gallons of crude have leaked so far from a major supply line, which ultimately delivers product to the Trans Alaskan Pipeline. This is now, unfortunately, the largest spill ever to occur on the North Slope, and one of the largest in Alaskan history. We understand that the failed line is currently being operated by BP Exploration (Alaska) Inc. (BP).

We are informed that, although company officials are still examining the root causes of the spill, the existing leak detection system failed to discover the leak. We also understand that the leading explanation appears to be corrosion and that this occurred in an area where the line dips underground at what is commonly called a "caribou crossing." While it is still unclear what caused the corrosion, we do understand that BP believes its onset was quite rapid and may have developed in as little as six months. Further, we are informed – through our staff's discussion with you and your staff – that this particular line had been tested using ultrasonic methods within the past six months, and that BP believes that the last period of testing found that the thickness of the areas of the pipe's walls that were tested were found to be within tolerance.

While we applaud such testing, we still remain unclear where such tests were taken and whether such tests were made on the section that ultimately failed. Moreover, we are unclear whether any of the spot testing associated with ultrasonic testing can or should be seen as representative of the entire line's condition. This is particularly important as we understand that this line had not been examined with a "smart pig" since 1998 – a process in which corrosion or other anomalies can be more thoroughly detected. In fact, we are still trying to understand the frequency at which this line was pigged (either via "maintenance pig" or "smart pig") and we look forward to receiving information that details both the frequency and method(s) used to examine this line. It is our understanding that such information will be made available to us soon.



Mr. Steve Marshall
Page 2

We recently received correspondence that raised some concerns about BP inspection methods, particularly those relating to corrosion matters. We therefore have several questions that we would ask you to respond to in order for us to better understand what specifically failed and what lessons have been learned to avoid future spills. As some of our questions may pertain to the upcoming reauthorization of the Pipeline Safety Improvement Act of 2002, we ask that you respond to the attached questions by no later than Monday, April 3, 2006.

We appreciate your cooperation and assistance in these matters of energy transport, security, and safety. If you need further information regarding this request, please contact us or our staff, Mr. Christopher Knauer with the Committee on Energy and Commerce Democratic staff at (202) 226-3400, or Mr. Jeff Petrich with the Committee on Resources Democratic staff at (202) 225-6065.

Sincerely,

George Miller

JOHN D. DINGELL
RANKING MEMBER
COMMITTEE ON ENERGY AND COMMERCE

GEORGE MILLER
MEMBER
COMMITTEE ON RESOURCES

Attachment

cc: The Honorable Joe Barton, Chairman
Committee on Energy and Commerce

Mr. Brigham McCown, Acting Administrator
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation

Questions for Steve Marshall, President
BP Exploration (Alaska) Inc.

1. Please provide a detailed schedule of all corrosion testing for the entire Oil Transit Line (OTL). For this effort, please delineate the type of testing used (e.g. visual, smart pigging, ultrasonic spot, etc.). Please also indicate where specifically any testing occurred.

2. Please indicate whether BP had any specific warning(s) that the OTL faced significant corrosion issues from within the company or through outside engineers or consultants. If so, did any reports or consultations predict problems in the low-lying caribou crossings? If so, please describe those reports or consultations.

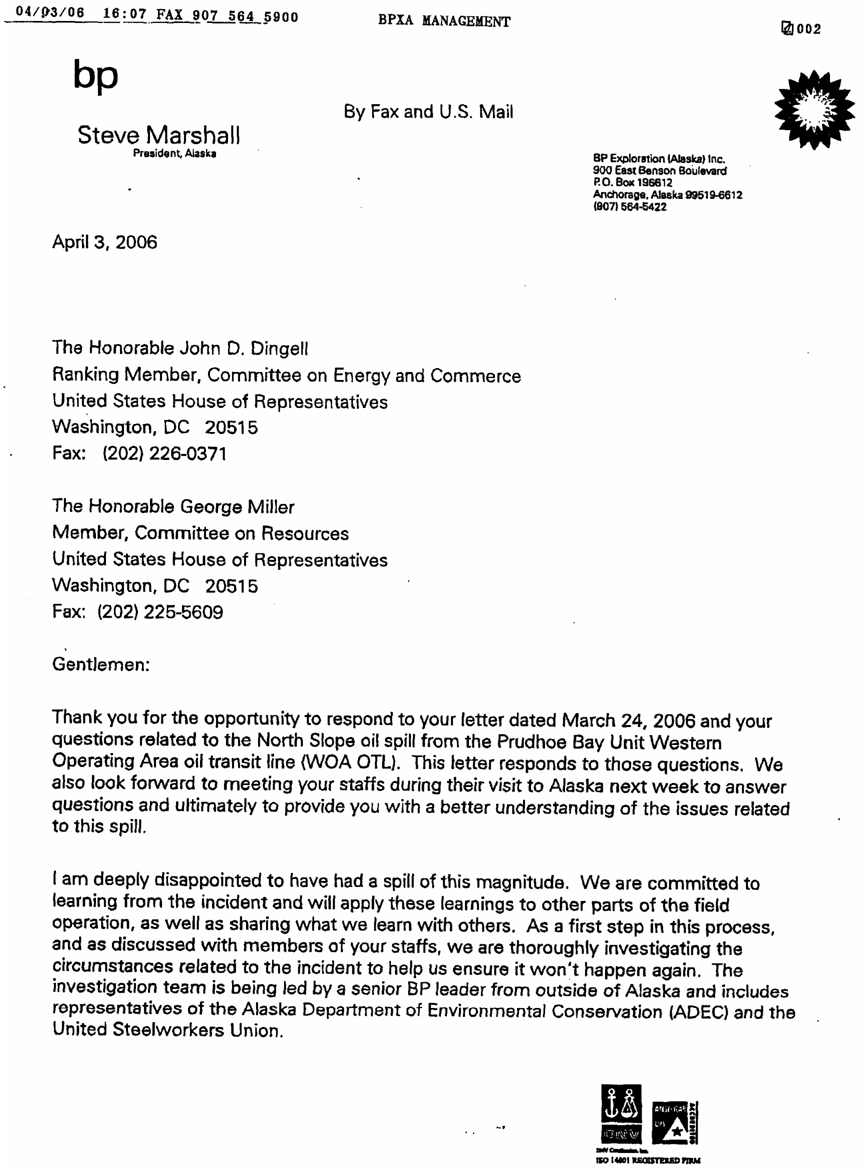
3. If the OTL had not been smart pigged since 1998 (as reports claim), please indicate why it was not deemed prudent by BP to apply technology with greater frequency to such a strategic line.

4. Please specify where ultrasonic tests were taken on the failed line prior to the leak, and where those tests were taken relative to the failed section. In particular, was the failed section tested prior to the leak? If not, why not? Also, does BP believe that a test measuring tolerances in one section of the OTL to be representative of tolerances for the entire line? Please explain.

5. It has been reported to us that the line in question, while having a low water cut, also has a very low flow rate and that this essentially makes the OTL a giant "oil-water separator." We are advised that results in the settlement of solids in the underlying layer of stagnant water. Is this the case? If so, what are or were the implications of this?

6. Were significant amounts of solids known to be present in the bottom of the line prior to the leak, particularly at the caribou crossings where the pipeline dips? Have significant amounts of sludge been found at the caribou crossings since examining the pipeline post leak? If solids were known, what concern(s) would this pose to the line? Also, if solids were deemed a concern, would a maintenance pig have been able to remove them and by removing them, would this in any way have made the line less likely to fail?

7. Please explain why the leak detection system on the OTL line failed to detect the leak and what changes will be made to leak detection systems on this and all of the BP North Slope lines.



04/03/06 16:07 FAX 907 564 5900 BPXA MANAGEMENT ☑002

bp

Steve Marshall
President, Alaska

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 564-5422

By Fax and U.S. Mail

April 3, 2006

The Honorable John D. Dingell
Ranking Member, Committee on Energy and Commerce
United States House of Representatives
Washington, DC 20515
Fax: (202) 226-0371

The Honorable George Miller
Member, Committee on Resources
United States House of Representatives
Washington, DC 20515
Fax: (202) 225-5609

Gentlemen:

Thank you for the opportunity to respond to your letter dated March 24, 2006 and your questions related to the North Slope oil spill from the Prudhoe Bay Unit Western Operating Area oil transit line (WOA OTL). This letter responds to those questions. We also look forward to meeting your staffs during their visit to Alaska next week to answer questions and ultimately to provide you with a better understanding of the issues related to this spill.

I am deeply disappointed to have had a spill of this magnitude. We are committed to learning from the incident and will apply these learnings to other parts of the field operation, as well as sharing what we learn with others. As a first step in this process, and as discussed with members of your staffs, we are thoroughly investigating the circumstances related to the incident to help us ensure it won't happen again. The investigation team is being led by a senior BP leader from outside of Alaska and includes representatives of the Alaska Department of Environmental Conservation (ADEC) and the United Steelworkers Union.

ISO 14001 REGISTERED FIRM

Although the investigation is not yet complete, the information available to the team suggests that recent and aggressive internal corrosion is the likely cause of the leak. Over 2000 inspections of our other Greater Prudhoe Bay oil transit lines conducted since the spill have not detected accelerated corrosion in any other lines, or in the other segments of the WOA OTL. Although the leak detection system worked as designed and met ADEC regulations, we still experienced a substantial spill. The investigation report is anticipated shortly. Beyond the report, we are committed to making improvements to our overall leak detection and surveillance program and will discuss our analysis with the relevant state and federal agencies.

We have included two attachments to further respond to the questions and points raised in your March 24 letter. You will see that we have expanded our response beyond the information you requested to provide a more complete description of our corrosion program.

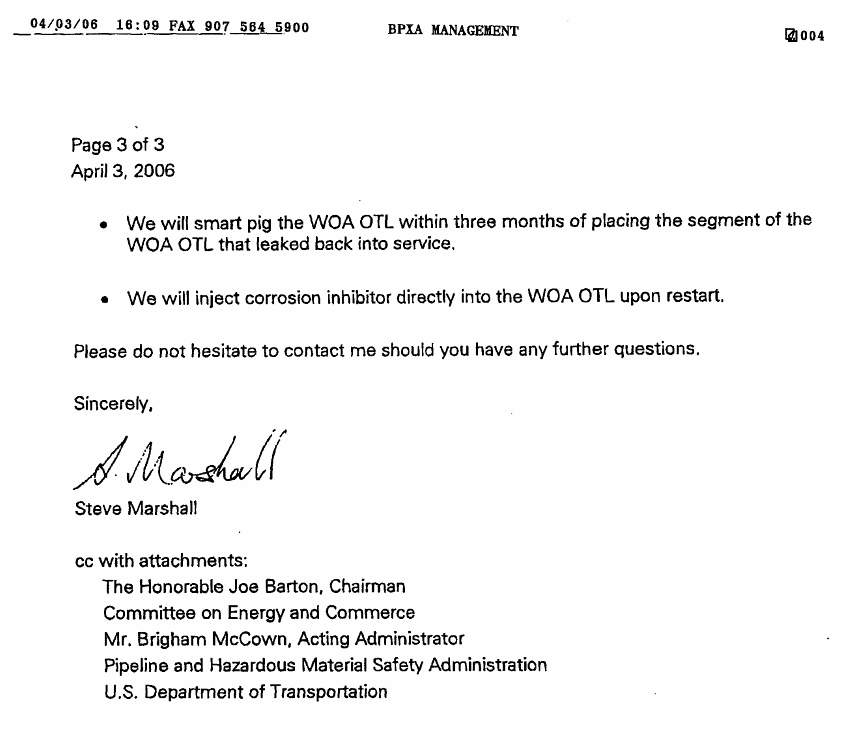
- Attachment 1 is a summary of BP Exploration (Alaska) Inc.'s (BPXA) corrosion monitoring and prevention program, which is reviewed every six months by ADEC. Based upon the data collected under our program, our corrosion technical specialists did not expect accelerated corrosion at this location because there was an established track record of low and manageable internal corrosion rates in this line.

- Attachment 2 contains our responses to the questions attached to your letter. The responses are based on our current understanding of the issues and the information that we have gathered to date.

On a forward basis, we have committed to several actions in response to the spill:

- We will clean up the spill to the highest standards that minimize damage to the environment.

- The WOA OTL segment from Gathering Center 2 (GC2) to Gathering Center 1 (GC1) will not be brought back into service until its integrity can be confirmed.



Page 3 of 3
April 3, 2006

- We will smart pig the WOA OTL within three months of placing the segment of the WOA OTL that leaked back into service.

- We will inject corrosion inhibitor directly into the WOA OTL upon restart.

Please do not hesitate to contact me should you have any further questions.

Sincerely,

S. Marshall

Steve Marshall

cc with attachments:
The Honorable Joe Barton, Chairman
Committee on Energy and Commerce
Mr. Brigham McCown, Acting Administrator
Pipeline and Hazardous Material Safety Administration
U.S. Department of Transportation

ATTACHMENT 1

BP Exploration (Alaska) Inc. (BPXA) - Corrosion Monitoring and Prevention Program

Background

BPXA's crude oil production facilities are located on the North Slope of Alaska. Prudhoe Bay is the largest of the five Alaskan oil fields operated by BPXA and was discovered in 1968. Oil production from Prudhoe Bay commenced in 1977, and remained at a rate of 1,500,000 barrels per day until 1989. Since 1989 production has declined to a current rate of just under 500,000 barrels of oil per day.

Numerous facilities and equipment have been built over the past 30 years to produce, process and transport crude oil from Prudhoe Bay and the four other production units that are operated by BPXA. Table 1 is a summary of the major facilities and equipment that have been built to produce oil from Alaskan fields that BPXA operates

The oil formations at Prudhoe Bay and other North Slope fields produce a mixture of oil, natural gas and water – these three components need to be separated before the oil can be delivered to the Trans Alaska Pipeline System. The associated natural gas contains carbon dioxide which dissolves in the water to form carbonic acid. This acid is corrosive to the carbon steel equipment, such as pipelines, and must be treated to mitigate its corrosive effects on the internal system components. The produced liquids may also entrain sand and rock particles which, at high velocity in the pipelines, can erode of the wall of the pipe. In addition, moisture on the outside of pipe from snow, rain, and condensation can cause external corrosion if they are allowed to contact the pipe.

Table 1: BPXA Operated Facilities

2,000 wells
1,500 miles of pipelines (not including TAPS)
3,500 Pressure Vessels
1,500 Tanks
11 Major Separation Plants
2 Major Gas Treating Plants
3 Major Water Treatment Plants

Program Objectives and the "Fit for Service" Strategy

The objective of BPXA's corrosion monitoring and prevention program is twofold –

1. Control corrosion in all equipment, pipelines, vessels and tanks.
2. Provide assurance that the equipment is in good condition – meaning it is safe to operate and will not release fluids into the environment.

Equipment that is in the safe and environmental sound condition described in objective two above is also referred to as being "Fit for Service". BPXA has designed our corrosion monitoring and prevention program around a "Fit for Service" strategy that has four key elements –

1. Identification of corrosion mechanisms for various equipment and lines (internal, external, erosion).
2. Frequent monitoring of corrosion rates through various corrosion monitoring programs.
3. Periodic inspections to identify corrosion damage and pipeline wall thickness.
4. Mitigating the progress of corrosion.

Specific Processes and Procedures

Numerous processes and procedures are utilized to deliver the Fit for Service strategy. These processes and procedures are summarized below.

Corrosion Monitoring: A variety of techniques are used to monitor the corrosion rates, including the use of metal weight loss coupons at over 5,000 locations. These coupons are inserted into the fluid stream. After the coupons have been exposed to the stream for a set period, they are removed and analyzed to determine the coupon corrosion rate. In addition, BPXA has installed 100 electrical resistance corrosion probes that continuously monitor the corrosivity of the fluids. The data obtained from the corrosion coupons and probes are used to adjust corrosion inhibitor injection rates and to initiate other corrosion mitigation actions.

Corrosion Mitigation: A variety of methods are used to mitigate corrosion. The type of method used is dependent upon the type of corrosion most likely to occur at a given location. Corrosion caused by the mixing of carbon dioxide (CO_2) and water, forming carbonic acid, is the most common type of internal corrosion in BPXA's facilities. CO_2 or carbonic acid corrosion is typically controlled by injection of corrosion inhibitor chemicals into the production streams. BPXA currently injects over 2.5 million gallons of corrosion inhibitor annually.

Bacterial corrosion resulting from bacteria and bacterial byproducts can also result in internal corrosion. Bacterial corrosion is controlled by injection of a biocide chemical. Many corrosion inhibitors contain quaternary amines, which also have biocide chemical properties. Mechanical pigging of pipelines is also used to remove solids and water that may build up in low points in the pipelines over time.

External corrosion of pipelines is controlled by replacing wet insulation or degraded coating with dry, sealed material.

Inspection: BPXA has one of the largest inspection programs in the oil and gas industry and currently inspects over 100,000 individual locations every year, for both internal (60,000) and external (40,000) corrosion. North Slope pipelines are unique compared to most oil and gas operations, as North Slope pipelines have been built above ground to prevent thawing of the permafrost and to protect the tundra. Even in areas where the pipelines are below ground, such as at road or caribou crossings, the pipelines are cased (i.e. placed within another larger pipe). The above ground pipeline configuration is advantageous to the corrosion monitoring program as it allows for significantly easier access for inspection compared to a buried pipeline.

Below are the inspection programs used to identify specific forms of corrosion damage.

- Corrosion Rate Monitoring (CRM) programs repeat inspections at the same location, typically every 6 months, to look for loss of metal.
- Corrosion Under Insulation (CUI) programs are designed to detect external corrosion that can be hidden by the thermal insulation that is on the outside of the pipelines.
- Erosion Rate Monitoring (ERM) is conducted at locations that could be susceptible to erosion inside the pipe due to high velocities and fluid characteristics. ERM is typically performed at bends every 3 months.

A variety of inspection techniques are used in the inspection programs described above. The techniques include **visual, ultrasonic, radiographic** and **magnetic flux** and each can be used to detect different types of damage. The basic technology in many of these techniques has also been built into devices which crawl, climb or travel along equipment to provide a "damage map" of large areas or all of a piece of equipment. For example, **smart pigs** can inspect the surface of an entire pipeline. Smart pigs and other automated techniques are helpful in identifying locations that should be more closely monitored using one of the point inspection methods, e.g visual, ultrasonic, radiographic. Smart pigs can also provide assurance that the spot inspections are truly representative of the pipeline condition. Again, the above-ground design of the North Slope pipelines makes it possible to monitor specific locations with potential damage with much greater frequency compared to buried pipelines.

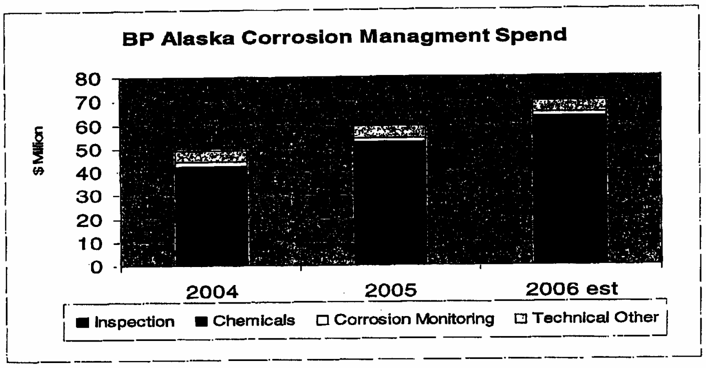
Below is overall summary list of the various inspection and monitoring techniques, some which are mentioned above as well as additional items.

Inspection Techniques
Radiography
Tangential radiography
Ultrasonic
Guided wave
Electro-magnetic pulse
Magnetic flux smart-pig

Corrosion Monitoring Techniques
Weight loss coupons
Electrical resistance probes
Galvanic probes
Linear polarization

Corrosion Program Resources and Results

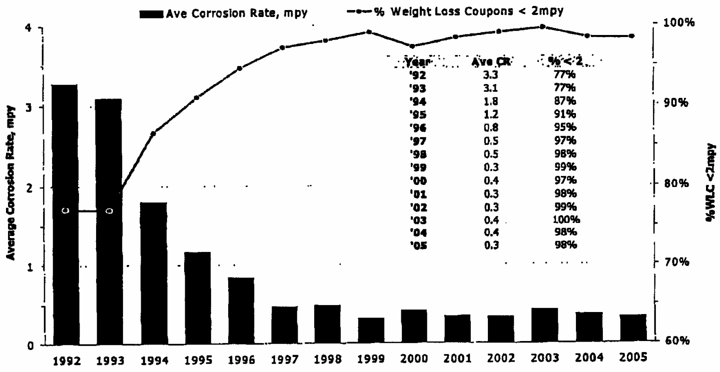
BPXA has been funding an ever more aggressive Corrosion, Inspection, Chemical (CIC) program to address the challenges posed by corrosion. Twenty-five BPXA engineers and technical specialists are teamed with an alliance of world leading suppliers of specialist services for inspection and chemicals. The 2006 annual budget for the program is $71 million, an increase of 15 percent from 2005, and 80% from 2001. The chart below illustrates the resource spend and commitment from 2004 through 2006.



BP Alaska Corrosion Managment Spend

Most important, a substantial improvement in control of internal corrosion in three phase flow lines (i.e. pipelines that transport oil, gas and water) has been seen over the past several years. The following graph illustrates the significant improvement in corrosion rates experienced since the early 1990s and the effective management of the corrosion rate over the past ten years. This plot shows the average corrosion rate on major production flow lines.

Internal Flow Line Corrosion Control



Year	Ave CR	% < 2
'92	3.3	77%
'93	3.1	77%
'94	1.8	87%
'95	1.2	91%
'96	0.8	95%
'97	0.5	97%
'98	0.5	98%
'99	0.3	99%
'00	0.4	97%
'01	0.3	98%
'02	0.3	99%
'03	0.4	100%
'04	0.4	98%
'05	0.3	98%

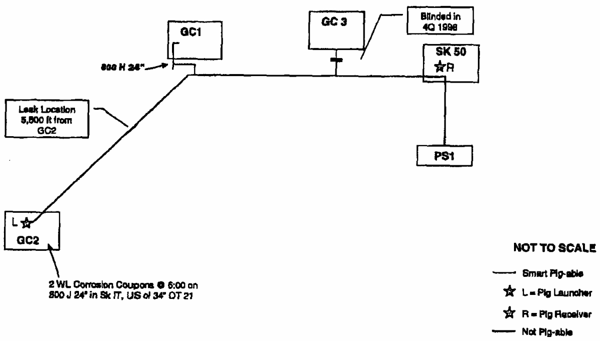
ATTACHMENT 2

Responses to Questions

1. Please provide a detailed schedule of all corrosion testing for the entire Oil Transit Line (OTL). For this effort, please delineate the type of testing used (e.g. visual, smart pigging, ultrasonic spot, etc.). Please also indicate where specifically any testing occurred.

The schematic below provides an illustration of the Prudhoe Bay Unit Western Operating Area Oil Transit Line (WOA OTL).

WOA Pipeline Schematic for Processed Sales Oil



The tables below provide detail on the corrosion monitoring and inspection programs applied to the WOA OTL from August 1998 (after the WOA OTL was last inspected using a smart pig) through February 2006.

Table I

WOA OTL Distribution of Inspections (August 1998 – February 2006)

Geographic Area	External Inspection	Internal Inspection	Cased Pipe Inspection
GC2 to GC1	85	149	10
GC1 to GC3	29	112	1
GC3 to Skid 50	77	127	13
*Skid 50 Bypass	10	491	-
Skid 50 to PS1	60	60	-

*Note: The bypass segment at Skid 50 was decommissioned in 2003

Table II
WOA OTL Inspection Program (August 1998 – February 2006)

Year	Nondestructive Test Method	No. of Inspections	Purpose of Assessment
1998	Ultrasonic Testing	29	Internal Corrosion
1998	Walking Speed Survey	1	Visual Mechanical Integrity Deficiencies
1999	Tangential Radiography	35	External Corrosion
1999	Ultrasonic Testing	134	External Corrosion
1999	Ultrasonic Testing	62	Internal Corrosion
2000	Electro-magnetic Testing	2	Cased Pipe Inspection/External Corrosion
2000	Guided Wave Inspection	1	Cased Pipe Inspection/Internal & External Corrosion
2000	Ultrasonic Testing	17	External Corrosion
2000	Ultrasonic Testing	246	Internal Corrosion
2001	Electro-magnetic Testing	2	Cased Pipe Inspection/External Corrosion
2001	Ultrasonic Testing	11	External Corrosion
2001	Radiographic Inspection	1	External Corrosion
2001	Ultrasonic Testing	263	Internal Corrosion
2002	Ultrasonic Testing	130	Internal Corrosion
2003	Tangential Radiography	2	External Corrosion
2003	Guided Wave Inspection	13	Cased Pipe Inspection/Internal & External Corrosion
2003	Ultrasonic Testing	21	External Corrosion
2003	Ultrasonic Testing	62	Internal Corrosion
2003	Walking Speed Survey	1	Visual Mechanical Integrity Deficiencies
2004	Tangential Radiography	40	External Corrosion
2004	Guided Wave Inspection	5	Cased Pipe Inspection/Internal & External Corrosion
2004	Ultrasonic Testing	40	Internal Corrosion
2005	Guided Wave Inspection	1	Cased Pipe Inspection/Internal & External Corrosion
2005	Ultrasonic Testing	107	Internal Corrosion

A further description of the various inspection and tests performed on the WOA OTL is summarized below.

(a) **Smart Pig** – The WOA OTL was inspected using a magnetic flux smart pig in 1990 and 1998. The line is scheduled to be inspected using a smart pig again during 2006. The "pig-able" section of the line from Gathering Center 2 ("GC-2") to Skid 50 ("SK 50") adjacent to Pump Station 1 of the Trans Alaska Pipeline was inspected.

(b) **Ultrasonic (UT) Inspections** – BPXA completed 1,122 individual UT inspections at both fixed and variable locations on the WOA OTL between July 23, 1998 (the date of the last smart pig run) and February 2006. "Fixed locations" are known damage sites where recurring inspections are performed to monitor corrosion growth. "Variable locations" are new locations added to discover potential areas of new corrosion. Table I above shows which section of the GPB OTL was inspected between August 1998 and February 2006. Table II shows the number of inspections between August 1998 and February 2006 relative to the geographic segment of pipeline. In addition, from March 2, 2006 through March 28, 2006, BPXA has completed over 2,000 inspections on the WOA OTL alone.

Exhibit A is an aerial overview of the WOA OTL with detailed inspection locations.

(c) **Guided Wave Inspections** – BPXA completed 20 guided wave inspections on the WOA OTL between August 1998 and February 2006. Table II shows the number of inspections and the year when they occurred. The guided wave inspections occurred at the road and caribou crossings along the WOA OTL.

Exhibit B is an aerial overview of the WOA OTL with crossing locations specified where the guided wave inspections were conducted. Guided wave inspections had been conducted at all of the road and caribou crossing locations from GC-2 to GC-1 with the exception of crossing R-1 at GC-2.

(d) **Weight Loss Coupons** – Coupon monitoring points are located on the WOA OTL within the Gathering Center 1 (GC1) and Gathering Center 2 (GC2) facilities. GC2 is located upstream of the failure point and GC1 is located downstream of the failure point. The coupons are analyzed every three months.

(e) **Electrical Resistance (ER) Probe** – ER Probes are located on the WOA OTL at both Gathering Center 2 and Gathering Center 1. Both ER probes are read and analyzed weekly.

(f) **Electromagnetic Pulse** – BPXA completed 4 electromagnetic pulse inspections on the WOA OTL between August 1998 and February 2006. Table II shows the number of inspections and the year when they occurred. The inspections occurred in the cased pipe sections of the WOA OTL (road or caribou crossings). The caribou crossing at the spill location had been inspected using the electromagnetic pulse method.

(g) **Tangential Radiography** - BPXA completed 77 tangential radiography inspections on the WOA OTL between August 1998 and February 2006. Table II shows the number of inspections and the year when they occurred.

(h) **Walking Speed Survey** – The WOA OTL was last examined with a Walking Speed Survey (WSS) in 2003 in locations that are accessible by foot. The WSS for the WOA OTL consists of a visual examination of the pipeline, supports and related components to identify mechanical integrity deficiencies.

2. Please indicate whether BP had any specific warning(s) that the OTL faced significant corrosion issues from within the company or through outside engineers or consultants. If so, did any reports or consultations predict problems in the low-lying caribou crossings? If so, please describe those reports or consultations.

BPXA is not presently aware of any specific warning that the WOA OTL faced a high risk of leaking due to accelerated internal corrosion at this location though we are continuing to check our monitoring data. The corrosion coupon data reviewed to date has indicated corrosion rates well below the BPXA standard target of 0.002 inches per year ("2 mils per year" or "2 mpy"). Corrosion coupon data have been demonstrated to be an effective way of measuring internal corrosion rates.

Similarly, annual ultrasonic (UT) inspection data showed manageable corrosion rates. There was some evidence of an increased internal corrosion rate in September 2005. In response, additional inspection points were added to the monitoring list and the inspection frequency was doubled. A smart pig run was scheduled for 2006.

BPXA was aware of the potential for external corrosion in low-lying caribou crossings, such as the type of external corrosion that caused the spill from the Y-36 three-phase flow line in 2003. BPXA undertook a number of actions after the Y-36 spill, including visual inspection of all caribou crossings, in order to make repairs at any locations that held accumulations of water – as was the case with Y-36.

The potential of external corrosion in cased pipe segments is being addressed in the inspection program by the use of smart pigging and long-range inspection techniques. These inspection techniques include electro-magnetic and guided-wave inspections. Only a small fraction of cross country pipelines are inaccessible to direct inspection methodologies such as visual, radiographic or ultrasonic inspection.

While cased pipe segments are often associated with dips in the pipelines not all dips are associated with cased segments. There is nothing about the casing itself that creates an environment for internal corrosion to occur and, certainly, the approximate 100 ft of piping inside the casing is often in a similar condition as the piping outside of the casing. As a result, assessment of internal corrosion in cased pipe segments can be inferred through examination of the piping outside of the casings.

BPXA's corrosion program and results are reviewed by ADEC on an annual basis.

3. If the OTL had not been smart pigged since 1998 (as reports claim), please indicate why it was not deemed prudent by BP to apply technology with greater frequency to such a strategic line.

The WOA OTL's above ground construction allows for more frequent and precise point inspections and monitoring when compared to a smart pig inspection. Frequent point inspections of areas with known corrosion using ultrasonic and other methods have been found to be a more effective method to monitor and adjust the corrosion prevention program thereby reducing the need for frequent smart pig runs.

Smart pigs do provide a comprehensive view on the condition of a pipeline. The results from smart pig runs are used to determine areas with potential damage that require recurring follow-up using UT and other point inspection technologies. The WOA OTL monitoring and inspection program followed this approach using the results from the two earlier smart pig inspections in 1990 and 1998, and the various point inspections, e.g. UT, guided wave.

The next smart pig inspection had been planned for 2006.

4. Please specify where ultrasonic tests were taken on the failed line prior to the leak, and where those tests were taken relative to the failed section. In particular, was the failed section tested prior to the leak? If not, why not? Also, does BP believe that a test measuring tolerances in one section of the OTL to be representative of tolerances for the entire line? Please explain.

As noted in the response to Question One, UT testing was done at a variety of fixed and variable locations prior to the leak since 1998.

Conventional UT was not taken at the leak location because it was in a buried crossing. The crossing had been tested using guided wave technology both prior to and post leak at the leak location. Guided wave technology provides a volumetric assessment of pipe-wall condition more suitable for broad areas of external corrosion metal loss rather than internal pitting. While the technique may have detected the corrosion pitting on the internal surface, guided wave technique does not provide quantitative information with exact measure of wall loss. The guided wave technique is used to screen for anomalies, monitor for active corrosion and where active corrosion is determined, corrective action is taken.

The 1998 smart pig did show 9% wall loss at the location of the leak. This wall loss occurred after 20 years of operation including the period when no formal inhibition programs were in place. The remaining 91% of wall thickness was judged to be more than sufficient to ensure integrity between the smart pigging runs.

As part of our corrosion monitoring program, 37 locations on the WOA OTL were re-examined with ultrasonic testing to assess pipe condition and corrosion rate between August 12, 2005 and September 9, 2005.

- 7 locations showed increasing corrosion damage with inspection intervals ranging from approximately 2 to 8 years and corrosion rates ranging from 9 to 32 mpy. (mpy equals 0.001 inch per year, or mil per year.) The severest corrosion penetration recorded was a pipe wall thickness 0.140 inches compared to the nominal pipe wall thickness of 0.380 inches.
- 30 locations showed no increased damage with inspection intervals ranging from approximately 1 to 10 years. The corrosion rates for these locations were zero and the severest corrosion penetration recorded was a pipe wall thickness of 0.180 inches compared to a nominal pipe wall thickness of 0.380 inches.

In October 2005, five of the same locations inspected between August and September were re-examined. None of the locations showed any increase in damage from the prior inspection one to two months earlier.

The nearest upstream and downstream locations to the leak site that were inspected in 2005 were approximately 4,600 feet upstream and 1,200 feet downstream. Neither of these locations showed any increase in corrosion in the 2005 survey.

Measurements in one location may be representative of other locations depending on the mechanism of damage. If the mechanism is understood, it is possible to identify the locations of highest risk and rely on measurements taken at those locations to be indicative of worst case corrosion rates. This is the basis for BPXA's risk based inspection. BPXA believes the six month spot inspection schedule for March 2006 would have detected the accelerated corrosion downstream of the leak location, which would likely have alerted BPXA to the possibility of accelerated corrosion within the caribou crossing.

5. It has been reported to us that the line in question, while having a low water cut, also has a very low flow rate and this essentially makes the OTL a giant "oil-water separator." We are advised that results in the settlement of solids in the underlying layer of stagnant water. Is this the case? If so, what are or were implications of this?

The flow in the WOA OTL has a low water cut because it carries sales quality crude. Although the flow rate has dropped to one-quarter of the peak rate, the velocity in this line has always been low. There is potential for internal corrosion along the bottom of the line as water or solids drop out or through microbiologically induced corrosion (MIC). Prior to this spill these risks were mitigated in two ways:

1. There are several stages of separation (oil, water and gas) with the final separator pressure at approximately 15 psig. This essentially removes all of the corrosive carbon dioxide gas and the majority of the solids.
2. Any water present in the oil should contain corrosion inhibitor carried over from treatment upstream. The presence of corrosion inhibitor would reduce any residual carbon dioxide corrosion rate to an acceptable level (<2 mpy). These corrosion inhibitors typically inhibit microbiological growth as well.

These mitigating measures were effective in mitigating internal corrosion for many years.

It should be noted that BPXA had an indication prior to the spill that something caused a reduction in the carry over of corrosion inhibitor in the water in this particular section of the WOA OTL, although we did not believe it to be a matter of serious concern. The investigation is still ongoing but there are two leading theories at this time: the inhibitor was absorbed onto the fine sand and/or the corrosion inhibitor effectiveness was reduced because of a reaction with an emulsion breaker used in the production facility to reduce the amount of water and flour silts in the oil transit line. To mitigate this effect, BPXA will directly inject corrosion inhibitor into the WOA OTL when GC2 restarts.

6. Were significant amounts of solids known to be present in the bottom of the line prior to the leak, particularly at the caribou crossings where the pipeline dips? Have significant amounts of sludge been found at the caribou crossings since examining the pipeline post leak? If solids were known, what concern(s) would this pose to the line? Also, if solids were deemed a concern, would a maintenance pig have been able to remove them and by removing them, would this in any way have made the line less likely to fail?

Records from the 1998 pigging program did not show an unusual presence of sediment in the WOA OTL. BPXA has no indication of the amount of sediment that might be present in the line at this time. We are currently researching methods which could be used to identify sediment in the line.

In the last one to two years BPXA Operations have seen an increase in fine sediment production (so called flour sands) into GC2 from the production of "viscous" oil. It may be possible that some portion of these sediments carried over into the oil transit line. If sediments do carry over, the main risk of corrosion would be from under-deposit or bacterial corrosion. It should be noted, however, that these same sediments should have carried through to the WOA OTL downstream of GC1. That portion of the WOA OTL does not appear to have experienced the same accelerated corrosion as did the segment from GC2 to GC1.

The risk from sediments has been discussed in Question Five. If sediments were believed to be a concern, a maintenance pigging program would be appropriate to remove them.

7. Please explain why the leak detection system on the OTL line failed to detect the leak and what changes will be made to leak detection systems on this and all of the BP North Slope lines.

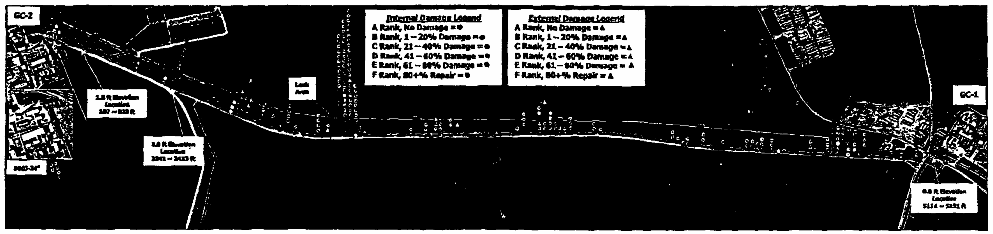
The leak detection system was demonstrated to meet the State of Alaska regulatory requirement of being able to detect a 1% leak over a 24 hour period. The joint BPXA and ADEC investigation team concluded the estimated leak rate was likely below the 1% threshold. Twice per day drive-by inspections are also completed by personnel trained in spill reporting. The leak occurred during winter conditions and went undetected because it was on the outboard side of a pipe rack from the road and was under drifted snow.

BPXA is analyzing ways to improve the overall leak detection and surveillance program on the WOA OTL and will provide a comprehensive review of possible improvements to ADEC and DOT in the coming months.

NOTE: We would like to take this opportunity to provide more information about the spill volume.

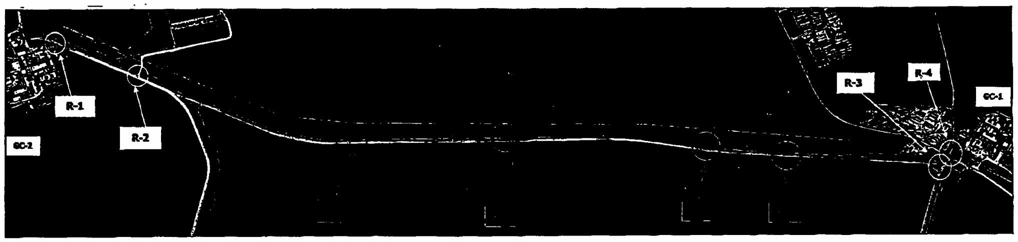
When the spill was discovered, production was immediately shut in without incident in an effort to minimize further impact. The Unified Command, which led the spill response and consists of the U.S. Environmental Protection Agency, ADEC, the North Slope Borough, and BPXA, estimated the spill volume on March 9 to be 4800 barrels +/- 33%, for a range of 3200 to 6400 barrels (134,783 to 267,500 gallons). Unfortunately, the lower figure (3200 barrels) was inadvertently dropped from the Unified Command's press release dated March 10. For a few days BPXA and the Unified Command reported the estimated spill volume to be 200,000 to 267,500 gallons. This was not accurate and we regret any confusion this may have caused. We do not anticipate that the spill volume estimate will be revised until a final number is determined at the end of the clean up.

Exhibit A

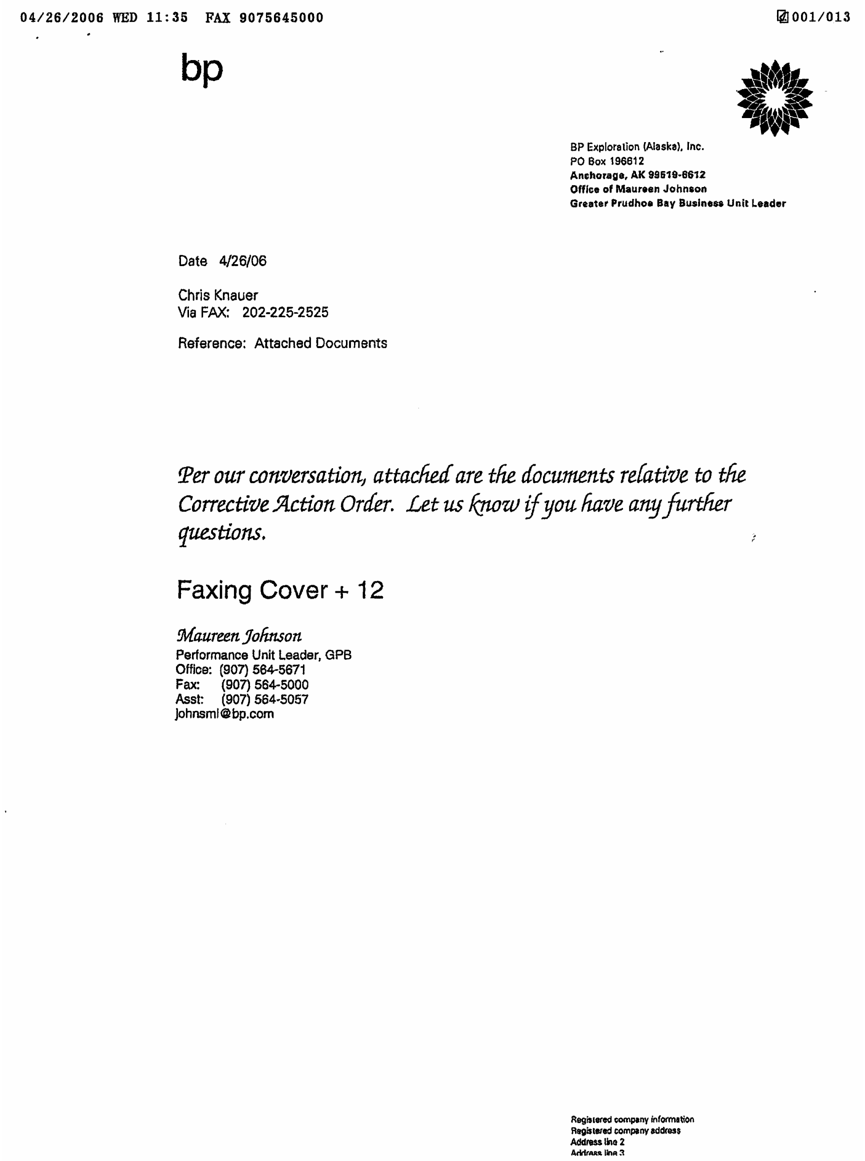

GC-2
1.5 ft Elevation Location
187 ~ 823 ft
3.0 ft Elevation Location
2341 ~ 2413 ft
B603-24"
Leak Area
Internal Damage Legend
A Rank, No Damage = ●
B Rank, 1 – 20% Damage = ●
C Rank, 21 – 40% Damage = ●
D Rank, 41 – 60% Damage = ●
E Rank, 61 – 80% Damage = ●
F Rank, 80+% Repair = ●
External Damage Legend
A Rank, No Damage = ▲
B Rank, 1 – 20% Damage = ▲
C Rank, 21 – 40% Damage = ▲
D Rank, 41 – 60% Damage = ▲
E Rank, 61 – 80% Damage = ▲
F Rank, 80+% Repair = ▲
GC-1
0.8 ft Elevation Location
5114 ~ 5151 ft

Aerial overview of the WOA OTL from GC2 to GC1 with the locations of the inspection points.

Exhibit B



Aerial overview of the WOA OTL from GC2 to GC1 with the locations of the caribou crossings (C-Crossing Number) and road crossing (R-Crossing Number).



04/26/2006 WED 11:35 FAX 9075645000 ☒001/013

BP Exploration (Alaska), Inc.
PO Box 196612
Anchorage, AK 99519-6612
Office of Maureen Johnson
Greater Prudhoe Bay Business Unit Leader

Date 4/26/06

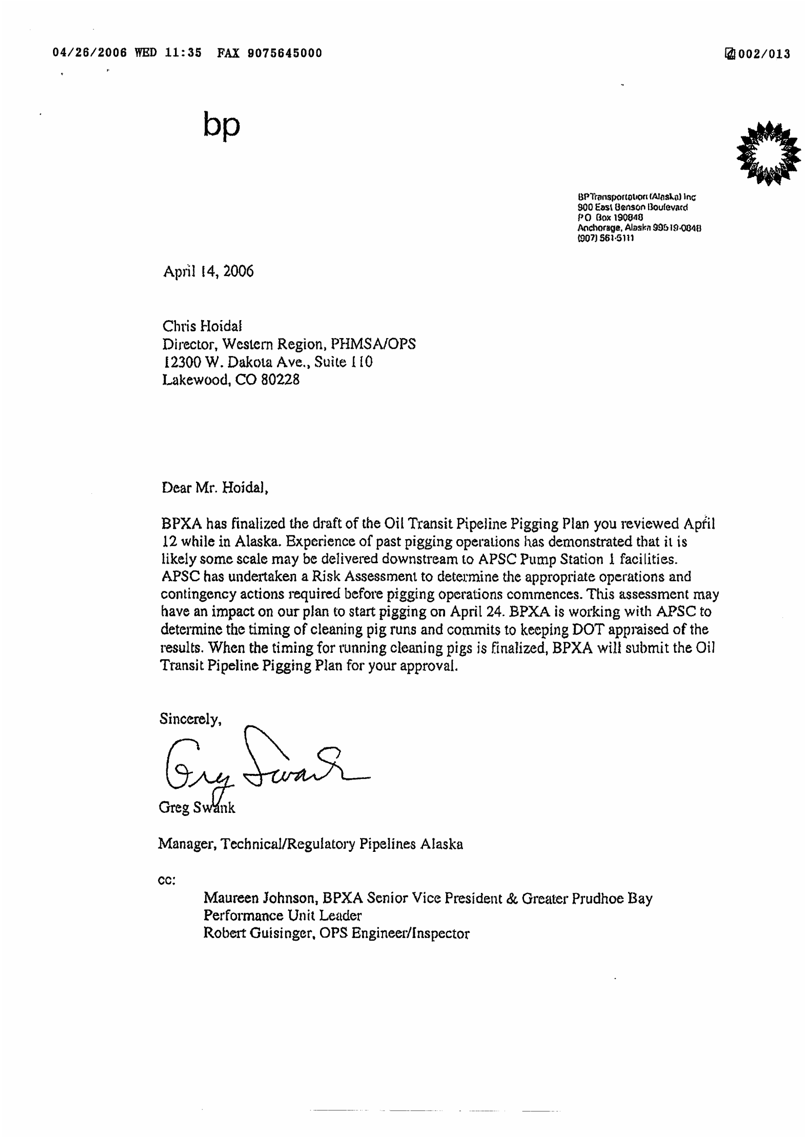
Chris Knauer
Via FAX: 202-225-2525

Reference: Attached Documents

Per our conversation, attached are the documents relative to the Corrective Action Order. Let us know if you have any further questions.

Faxing Cover + 12

Maureen Johnson
Performance Unit Leader, GPB
Office: (907) 564-5671
Fax: (907) 564-5000
Asst: (907) 564-5057
johnsml@bp.com



bp

BP Transportation (Alaska) Inc
900 East Benson Boulevard
P O Box 190848
Anchorage, Alaska 99519-0848
(907) 561-5111

April 14, 2006

Chris Hoidal
Director, Western Region, PHMSA/OPS
12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

Dear Mr. Hoidal,

BPXA has finalized the draft of the Oil Transit Pipeline Pigging Plan you reviewed April 12 while in Alaska. Experience of past pigging operations has demonstrated that it is likely some scale may be delivered downstream to APSC Pump Station 1 facilities. APSC has undertaken a Risk Assessment to determine the appropriate operations and contingency actions required before pigging operations commences. This assessment may have an impact on our plan to start pigging on April 24. BPXA is working with APSC to determine the timing of cleaning pig runs and commits to keeping DOT appraised of the results. When the timing for running cleaning pigs is finalized, BPXA will submit the Oil Transit Pipeline Pigging Plan for your approval.

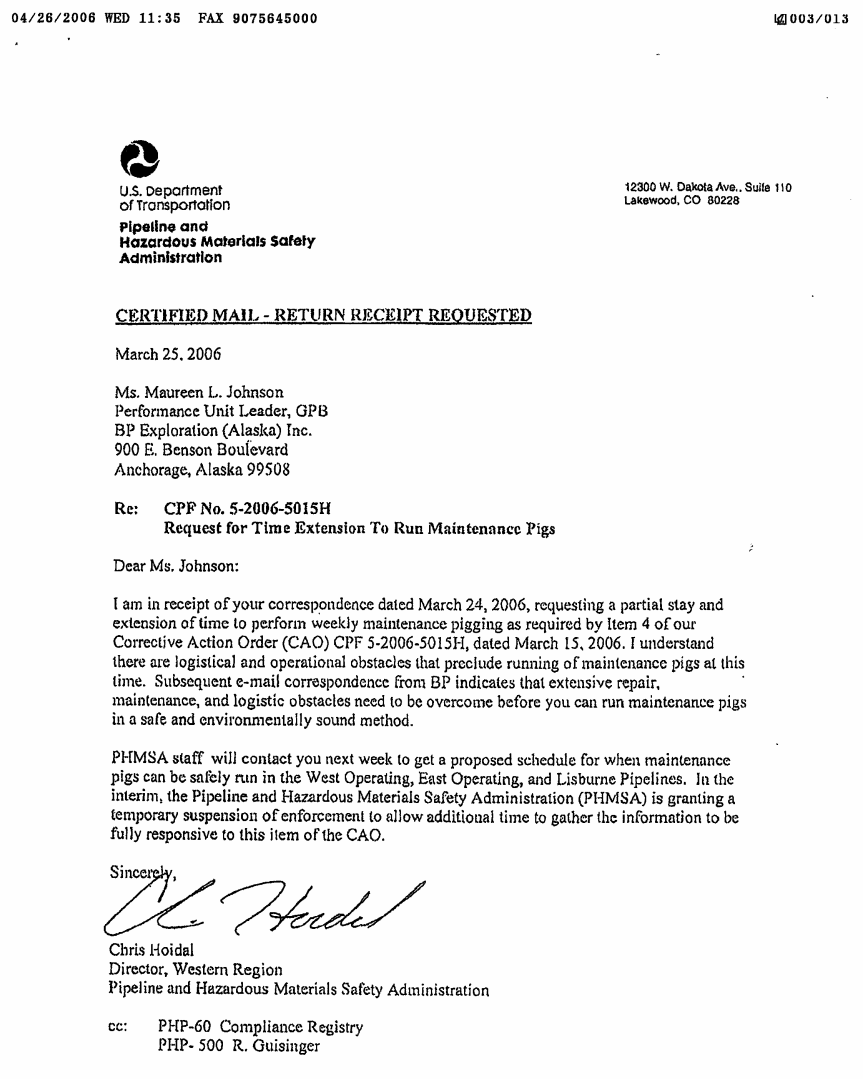
Sincerely,

Greg Swank

Greg Swank

Manager, Technical/Regulatory Pipelines Alaska

cc:
Maureen Johnson, BPXA Senior Vice President & Greater Prudhoe Bay Performance Unit Leader
Robert Guisinger, OPS Engineer/Inspector



U.S. Department
of Transportation
**Pipeline and
Hazardous Materials Safety
Administration**

12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

March 25, 2006

Ms. Maureen L. Johnson
Performance Unit Leader, GPB
BP Exploration (Alaska) Inc.
900 E. Benson Boulevard
Anchorage, Alaska 99508

Re: **CPF No. 5-2006-5015H**
Request for Time Extension To Run Maintenance Pigs

Dear Ms. Johnson:

I am in receipt of your correspondence dated March 24, 2006, requesting a partial stay and extension of time to perform weekly maintenance pigging as required by Item 4 of our Corrective Action Order (CAO) CPF 5-2006-5015H, dated March 15, 2006. I understand there are logistical and operational obstacles that preclude running of maintenance pigs at this time. Subsequent e-mail correspondence from BP indicates that extensive repair, maintenance, and logistic obstacles need to be overcome before you can run maintenance pigs in a safe and environmentally sound method.

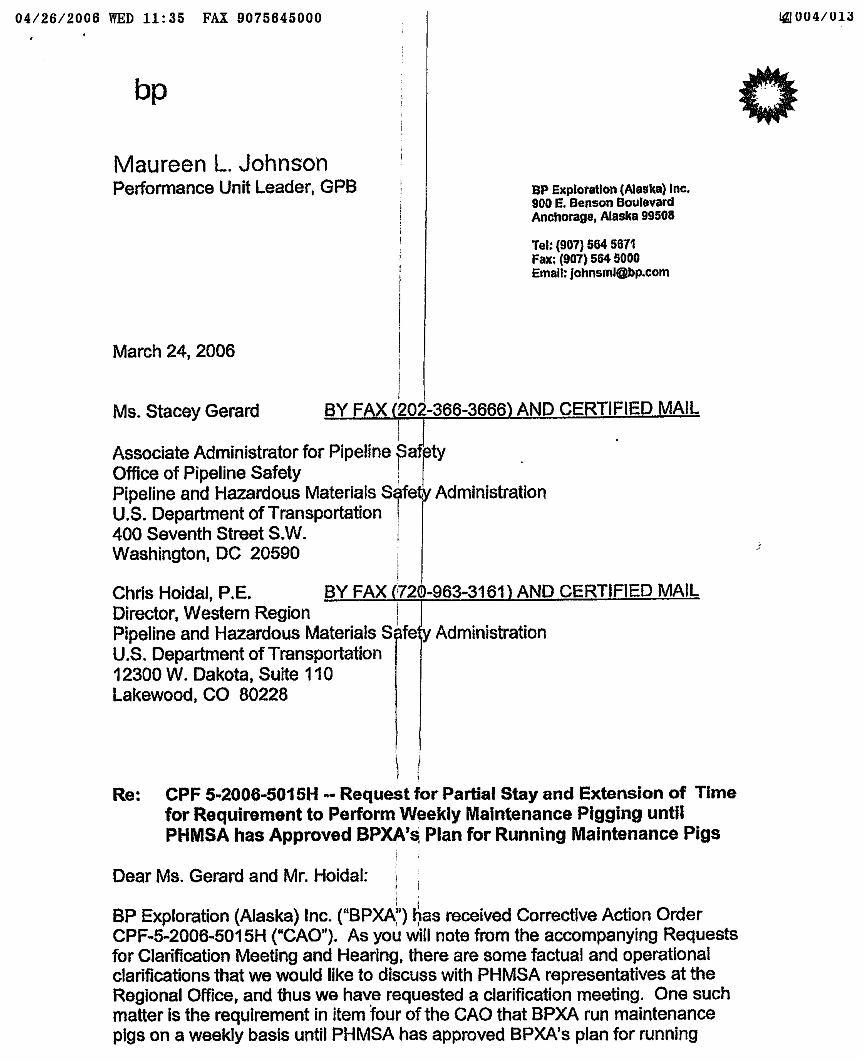
PHMSA staff will contact you next week to get a proposed schedule for when maintenance pigs can be safely run in the West Operating, East Operating, and Lisburne Pipelines. In the interim, the Pipeline and Hazardous Materials Safety Administration (PHMSA) is granting a temporary suspension of enforcement to allow additional time to gather the information to be fully responsive to this item of the CAO.

Sincerely,

C. Hoidal

Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration

cc: PHP-60 Compliance Registry
PHP- 500 R. Guisinger



bp

Maureen L. Johnson
Performance Unit Leader, GPB

BP Exploration (Alaska) Inc.
900 E. Benson Boulevard
Anchorage, Alaska 99508

Tel: (907) 564 5671
Fax: (907) 564 5000
Email: johnsml@bp.com

March 24, 2006

Ms. Stacey Gerard BY FAX (202-366-3666) AND CERTIFIED MAIL

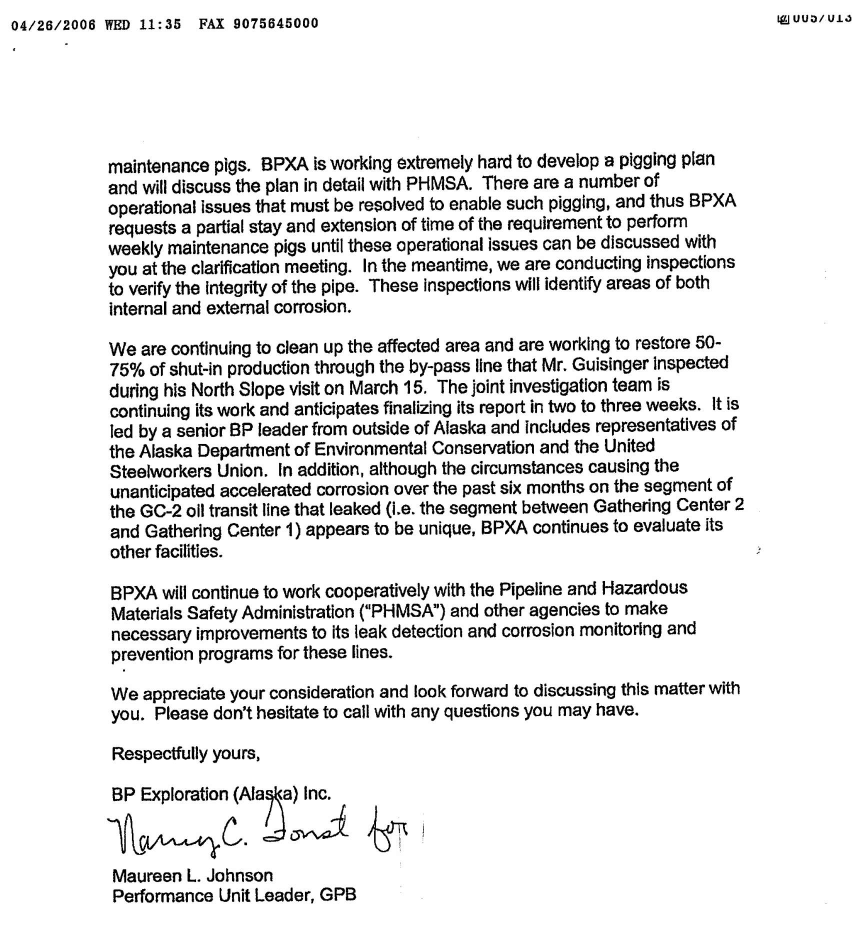
Associate Administrator for Pipeline Safety
Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
400 Seventh Street S.W.
Washington, DC 20590

Chris Hoidal, P.E. BY FAX (720-963-3161) AND CERTIFIED MAIL
Director, Western Region
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
12300 W. Dakota, Suite 110
Lakewood, CO 80228

Re: CPF 5-2006-5015H -- Request for Partial Stay and Extension of Time for Requirement to Perform Weekly Maintenance Pigging until PHMSA has Approved BPXA's Plan for Running Maintenance Pigs

Dear Ms. Gerard and Mr. Hoidal:

BP Exploration (Alaska) Inc. ("BPXA") has received Corrective Action Order CPF-5-2006-5015H ("CAO"). As you will note from the accompanying Requests for Clarification Meeting and Hearing, there are some factual and operational clarifications that we would like to discuss with PHMSA representatives at the Regional Office, and thus we have requested a clarification meeting. One such matter is the requirement in item four of the CAO that BPXA run maintenance pigs on a weekly basis until PHMSA has approved BPXA's plan for running



maintenance pigs. BPXA is working extremely hard to develop a pigging plan and will discuss the plan in detail with PHMSA. There are a number of operational issues that must be resolved to enable such pigging, and thus BPXA requests a partial stay and extension of time of the requirement to perform weekly maintenance pigs until these operational issues can be discussed with you at the clarification meeting. In the meantime, we are conducting inspections to verify the integrity of the pipe. These inspections will identify areas of both internal and external corrosion.

We are continuing to clean up the affected area and are working to restore 50-75% of shut-in production through the by-pass line that Mr. Guisinger inspected during his North Slope visit on March 15. The joint investigation team is continuing its work and anticipates finalizing its report in two to three weeks. It is led by a senior BP leader from outside of Alaska and includes representatives of the Alaska Department of Environmental Conservation and the United Steelworkers Union. In addition, although the circumstances causing the unanticipated accelerated corrosion over the past six months on the segment of the GC-2 oil transit line that leaked (i.e. the segment between Gathering Center 2 and Gathering Center 1) appears to be unique, BPXA continues to evaluate its other facilities.

BPXA will continue to work cooperatively with the Pipeline and Hazardous Materials Safety Administration ("PHMSA") and other agencies to make necessary improvements to its leak detection and corrosion monitoring and prevention programs for these lines.

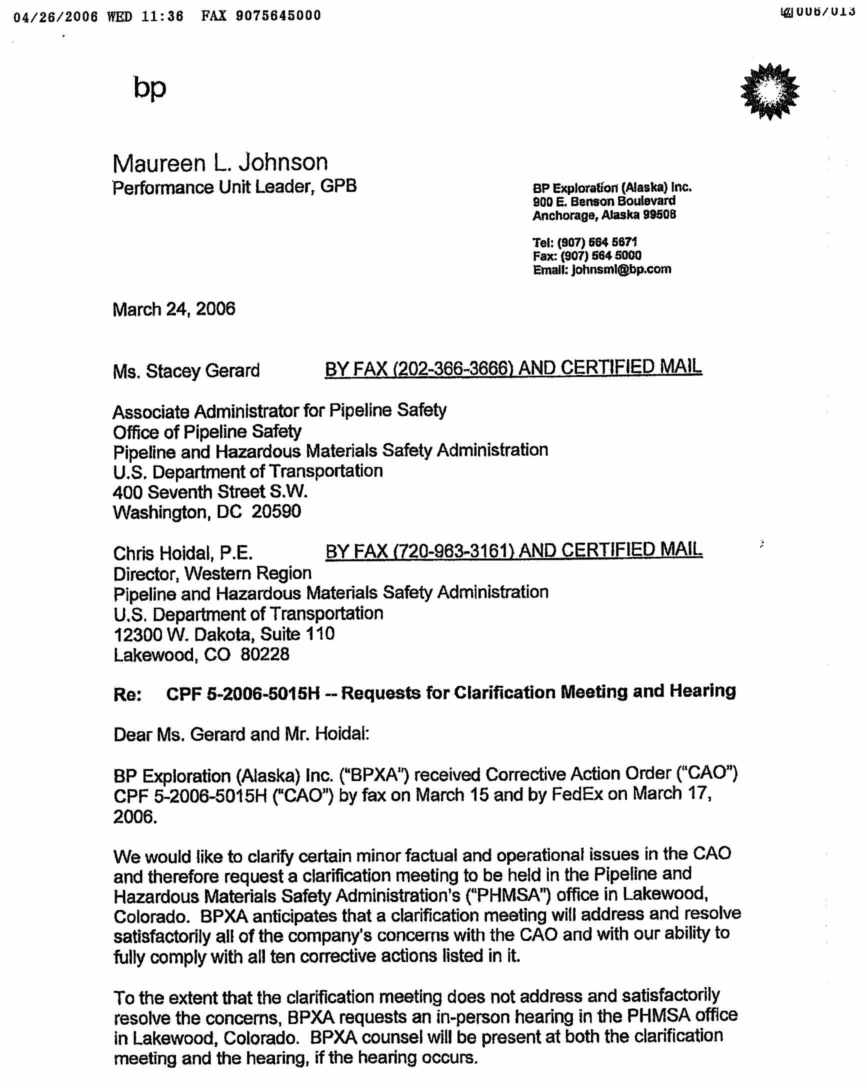
We appreciate your consideration and look forward to discussing this matter with you. Please don't hesitate to call with any questions you may have.

Respectfully yours,

BP Exploration (Alaska) Inc.

Nancy C. Donat for

Maureen L. Johnson
Performance Unit Leader, GPB



04/26/2006 WED 11:36 FAX 9075645000 006/013

bp

Maureen L. Johnson
Performance Unit Leader, GPB

BP Exploration (Alaska) Inc.
900 E. Benson Boulevard
Anchorage, Alaska 99508

Tel: (907) 564 5671
Fax: (907) 564 5000
Email: johnsml@bp.com

March 24, 2006

Ms. Stacey Gerard BY FAX (202-366-3666) AND CERTIFIED MAIL

Associate Administrator for Pipeline Safety
Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
400 Seventh Street S.W.
Washington, DC 20590

Chris Hoidal, P.E. BY FAX (720-963-3161) AND CERTIFIED MAIL
Director, Western Region
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
12300 W. Dakota, Suite 110
Lakewood, CO 80228

Re: CPF 5-2006-5015H -- Requests for Clarification Meeting and Hearing

Dear Ms. Gerard and Mr. Hoidal:

BP Exploration (Alaska) Inc. ("BPXA") received Corrective Action Order ("CAO") CPF 5-2006-5015H ("CAO") by fax on March 15 and by FedEx on March 17, 2006.

We would like to clarify certain minor factual and operational issues in the CAO and therefore request a clarification meeting to be held in the Pipeline and Hazardous Materials Safety Administration's ("PHMSA") office in Lakewood, Colorado. BPXA anticipates that a clarification meeting will address and resolve satisfactorily all of the company's concerns with the CAO and with our ability to fully comply with all ten corrective actions listed in it.

To the extent that the clarification meeting does not address and satisfactorily resolve the concerns, BPXA requests an in-person hearing in the PHMSA office in Lakewood, Colorado. BPXA counsel will be present at both the clarification meeting and the hearing, if the hearing occurs.

Please be advised that while BPXA does not agree with the statement that the continued operation of these lines will be hazardous to life, property, and the environment, BPXA will not contest the PHMSA's authority to issue the CAO or PHMSA's jurisdiction in this matter.

Statement of Issues

1. BPXA seeks clarifications of the CAO, including definitions for the PBWOA, PBEOA and Lisburne oil transit pipelines; the definition of anomaly; information regarding the leak detection system, corrosion mechanism, pipeline characteristics and dates of construction; the lack of water next to the line at the leak location; the quality of crude oil transported in the lines; our corrosion inspection program; additional anomalies; operational and maintenance practices on the three lines; known corrosion rates on the three lines; and operational and timing issues regarding maintenance pigs and line pressures during normal operations and pigging.

In the event a hearing is necessary and has to be scheduled after the clarification meeting, BPXA would also like the opportunity to review the material in the case file in order to better respond to the questions that may come up on the remaining issues.

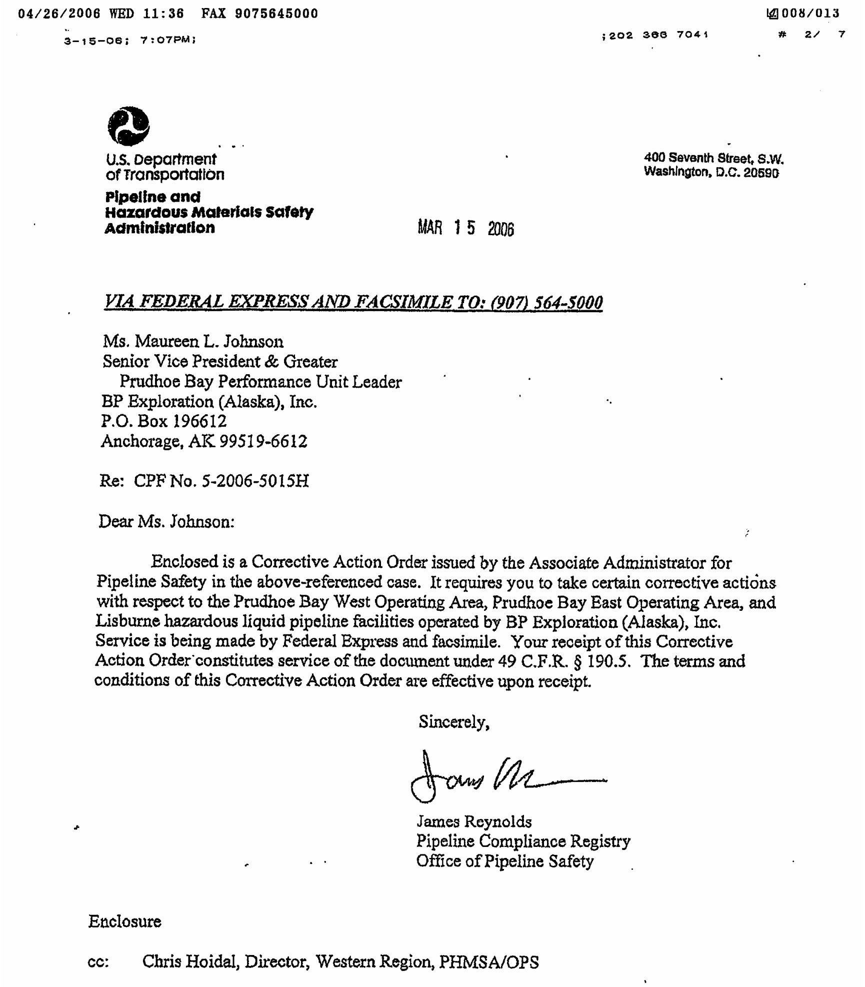
Please don't hesitate to call with any questions you may have.

Respectfully yours,

BP Exploration (Alaska) Inc.

Nancy C. Foust for

Maureen L. Johnson
Performance Unit Leader, GPB



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3-15-06; 7:07PM; ;202 366 7041 # 2/ 7

U.S. Department
of Transportation
**Pipeline and
Hazardous Materials Safety
Administration**

400 Seventh Street, S.W.
Washington, D.C. 20590

MAR 15 2006

VIA FEDERAL EXPRESS AND FACSIMILE TO: (907) 564-5000

Ms. Maureen L. Johnson
Senior Vice President & Greater
Prudhoe Bay Performance Unit Leader
BP Exploration (Alaska), Inc.
P.O. Box 196612
Anchorage, AK 99519-6612

Re: CPF No. 5-2006-5015H

Dear Ms. Johnson:

Enclosed is a Corrective Action Order issued by the Associate Administrator for Pipeline Safety in the above-referenced case. It requires you to take certain corrective actions with respect to the Prudhoe Bay West Operating Area, Prudhoe Bay East Operating Area, and Lisburne hazardous liquid pipeline facilities operated by BP Exploration (Alaska), Inc. Service is being made by Federal Express and facsimile. Your receipt of this Corrective Action Order constitutes service of the document under 49 C.F.R. § 190.5. The terms and conditions of this Corrective Action Order are effective upon receipt.

Sincerely,

James Reynolds
Pipeline Compliance Registry
Office of Pipeline Safety

Enclosure

cc: Chris Hoidal, Director, Western Region, PHMSA/OPS

DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, DC 20590

In the Matter of)
BP Exploration (Alaska), Inc.,) CPF No. 5-2006-5015H
Respondent)

CORRECTIVE ACTION ORDER

Purpose and Background

This Corrective Action Order is being issued, under authority of 49 U.S.C. § 60112, to require BP Exploration (Alaska), Inc. (Respondent), to take necessary corrective action to protect the public, property, and the environment from potential hazards associated with a failure involving Respondent's Prudhoe Bay West Operating Area (PBWOA) hazardous liquid pipeline.

On March 2, 2006, Respondent discovered a leak on the PBWOA hazardous liquid pipeline in North Slope Borough, Alaska. The probable cause of the failure is internal corrosion. Pursuant to 49 U.S.C. § 60117, the Pipeline and Hazardous Materials Safety Administration (PHMSA) initiated an investigation of the accident.

Preliminary Findings

- On March 2, 2006, at approximately 5:30 AM AKST, Respondent's surveillance crew discovered a crude oil spill in the proximity of Respondent's PBWOA hazardous liquid transmission pipeline in North Slope Borough, Alaska. Respondent determined the failure site to be at or near Mile 1.0 between Gathering Center 2 (GC-2) and Gathering Center 1 (GC-1) on the PBWOA pipeline, several miles upstream of the Trans Alaska Pipeline's first pump station (PS-1). No fires, injuries, or fatalities were reported in connection with the accident.
- The pipeline failure resulted in a release currently estimated at 5,000 barrels of processed crude oil, impacting the arctic tundra and covering approximately 2 acres of permafrost. Potential damage to the ecology and environment is presently unknown.
- Respondent's leak detection system was not effective in recognizing and identifing the failure. Following discovery of the spill, Respondent isolated the segment between GC-2

and GC-1, initiated shutdown at 6:49 AM AKST and depressurized the segment. Respondent located the leak site and installed a containment welded sleeve. Respondent also initiated oil spill response.

- The failure point is a 0.25-inch by 0.5-inch hole in the pipe. The probable cause of the failure is internal corrosion. There is evidence of bacterial corrosion (increased hydrogen sulfide and nitric acid in the crude oil) and increased water content.
- Respondent's PBWOA hazardous liquid pipeline system is approximately 10 miles in length and transports processed crude oil from GC-2 to PS-1 on the Trans Alaska Pipeline in North Slope, Alaska. The PBWOA system is constructed of 34-inch nominal diameter, X52 Grade, 0.375-inch wall thickness, submerged arc welded pipe manufactured in 1975 through 1977. The pipe is not coated and it is not cathodically protected. The pipeline sits on a vertical support member above-ground and is surrounded by an air culvert. The pipe is insulated and has a steel jacket. Although the pipeline is above-ground, at the time of the failure, the pipeline was lying in water that had pooled from melting snow.
- The established maximum operating pressure (MOP) for the PBWOA is 826 pounds per square inch gauge (psig) established by design pressure. Estimated maximum normal operating pressure is 100 psig. Actual operating pressure was approximately 80 psig when the failure was discovered.
- The PBWOA operates at less than 20% of the specified minimum yield strength (SMYS) and is therefore a low-stress pipeline under 49 C.F.R. § 195.2. Federal hazardous liquid pipeline safety regulations (49 C.F.R. Part 195) do not apply to the PBWOA under the exception in 49 C.F.R. § 195.1 for onshore low-stress pipelines located in a rural area, outside a waterway currently used for commercial navigation, which do not transport highly volatile liquids.
- The PBWOA is one of three similar low-stress pipelines operated by Respondent that feed into PS-1. The other two pipelines are the Prudhoe Bay East Operating Area (PBEOA) pipeline and the Lisburne pipeline. All three pipelines were constructed around the same time, operate in similar environmental conditions, transport the same quality crude oil that contributed to the cause of the internal corrosion in PBWOA, and are operated and maintained in a similar manner by Respondent.
- Respondent's failure investigation has identified at least six additional anomalies on the PBWOA segment between GC-2 and GC-1. Internal corrosion has been observed at several of those anomalies. The worst noted anomaly had a remaining wall thickness of 0.04-inches.
- An internal inspection of the PBWOA was last performed in 1998 using a high-resolution magnetic flux leakage (MFL) tool. Respondent has not established a regular internal inspection or maintenance pigging (cleaning pig) program.
- Respondent plans to bypass the segment between GC-2 and GC-1 using a 24-inch flow-line. Once the bypass is in place, Respondent plans to restart the PBWOA. Respondent

anticipates the bypass process will take up to 10 days before the PBWOA pipeline can be restarted.

Determination of Necessity for Corrective Action Order and Right to Hearing

Section 60112 of Title 49, United States Code, provides for the issuance of a Corrective Action Order, after reasonable notice and the opportunity for a hearing, when PHMSA decides that a pipeline facility is hazardous. A pipeline facility is a pipeline, right-of-way, facility, building, or equipment used or intended to be used in the movement of hazardous liquid by pipeline, or the storage of hazardous liquid incidental to the movement of hazardous liquid by pipeline, in or affecting interstate or foreign commerce. A pipeline facility does not include movement of hazardous liquid through gathering lines in a rural area; onshore production, refining, or manufacturing facilities; or storage or in-plant piping systems associated with onshore production, refining, or manufacturing facilities. The basis for deciding that a pipeline facility is hazardous, requiring corrective action, is set forth both in the above-referenced statute and 49 C.F.R. § 190.233, a copy of which is enclosed.

Section 60112 of Title 49, United States Code, and the regulations promulgated thereunder, provide for the issuance of a Corrective Action Order without prior opportunity for notice and hearing upon a finding that a failure to issue the Order expeditiously will likely result in serious harm to life, property, or the environment. In such cases, an opportunity for a hearing will be provided as soon as practicable after the issuance of the Order.

After evaluating the foregoing preliminary findings of fact, I find that the PBWOA, PBEOA, and Lisburne pipelines operated by Respondent are pipeline facilities within the meaning of that term as used in 49 U.S.C. §§ 60101 and 60112, notwithstanding the inapplicability of the pipeline safety regulations at 49 C.F.R. Part 195. Those pipelines are used in the movement of hazardous liquid by pipeline in interstate commerce and are not gathering lines in a rural area, onshore production, refining, or manufacturing facilities, or in-plant piping systems. Additionally, after considering the age of the pipe, the hazardousness of the product the pipelines transport, the large spill volume, the ineffectiveness of the leak detection system to identify the leak, the number, type, and severity of anomalies discovered on the segment that was inspected, the similarity of the PBEOA and Lisburne pipelines to the pipeline that failed, and the proximity of the pipelines to wildlife areas or other possible sensitive areas, I find that the continued operation of Respondent's PBWOA, PBEOA, and Lisburne hazardous liquid pipelines without corrective measures will be hazardous to life, property, and the environment. Moreover, failure to expeditiously issue this Order requiring immediate corrective action would likely result in serious harm to life, property, or the environment.

Accordingly, this Corrective Action Order mandating immediate corrective action is issued without prior notice and opportunity for hearing. The terms and conditions of this Order are effective upon receipt.

Within 10 days of receipt of this Order, Respondent may request a hearing, to be held as soon as practicable, by notifying the Associate Administrator for Pipeline Safety in writing, delivered personally, by mail or by facsimile at (202) 366-4566. The hearing will be held in Lakewood, Colorado or Washington, D.C. on a date that is mutually convenient to PHMSA and the Respondent.

After receiving and analyzing additional data in the course of this investigation, PHMSA may identify other corrective action measures that need to be taken. In that event, Respondent will be notified of any additional measures required and amendment of this Order will be considered. To the extent it is consistent with safety considerations, Respondent will be afforded notice and an opportunity for a hearing prior to the imposition of additional corrective measures.

Required Corrective Action

Pursuant to 49 U.S.C. § 60112, I hereby order BP Exploration (Alaska), Inc. to immediately take the following corrective actions with respect to the PBWOA, PBEOA, and Lisburne hazardous liquid pipeline systems:

1. Repair all anomalies on the PBWOA segment between GC-2 and GC-1, including those anomalies identified after the March 2, 2006 pipeline failure before resuming service. Extract and record dimensional data of all anomalies found, including data on distance from upstream and downstream girth weld, o'clock position, minimum and maximum remaining wall thickness, and remedial actions taken on each anomaly.

2. Obtain prior written approval from the Director, Western Region, PHMSA before resuming operations on the PBWOA pipeline. Operating pressure on the PBWOA is not to exceed 80 psig. This pressure restriction shall remain in effect until written approval to increase the pressure is obtained from the Director, Western Region, PHMSA.

3. Perform an internal inspection using a calibrated smart pig on the PBWOA pipeline within 3 months of placing the pipeline back in service. Take appropriate action to address all anomalies discovered by this inline inspection device, in accordance with the standards for anomaly repair in 49 C.F.R. Part 195. Record differences between inline inspection data and actual "as found" data for all anomalies and integrate that data in future analyses, mapping corrosion growth, and confirming data gathered by inline inspection tool. Develop and submit for approval a plan to perform internal inspections at regular intervals, not to exceed 5 years, and schedule for the repair of anomalies identified through those inspections. Implement that plan upon approval.

4. Develop and submit for approval a plan for running maintenance pigs (cleaning pigs) on the PBWOA, PBEOA, and Lisburne pipelines at regular intervals. Implement that plan upon approval. Until that plan has been approved and implemented, run maintenance pigs on those pipelines on a weekly basis. Conduct laboratory analyses on sludge to determine its corrosive properties and integrate those findings into the internal corrosion management plan in Item 5 below.

5. Conduct a review of the leak detection system for the PBWOA, PBEOA, and Lisburne pipelines and make necessary modifications to ensure that the leak detection systems comply with API 1130, within 3 months of receipt of this order.

6. Develop and submit for approval an internal corrosion management plan to reduce internal corrosion on the PBWOA, PBEOA, and Lisburne pipelines within 3 months of receipt of this order. The plan must address the use of corrosion inhibitors, emulsion breakers, and mechanisms to reduce water and solid particles. This plan should also allow for monitoring sludge extracted from pipelines to ensure that internal corrosion is being controlled. Implement that plan upon approval.

7. Perform an internal inspection using a calibrated smart pig on the PBEOA and Lisburne pipelines within 3 months of receipt of this Order. Take appropriate action to address all anomalies discovered, in accordance with the standards for anomaly repair in 49 C.F.R. Part 195. Record differences between inline inspection data and actual "as found" data for all anomalies and integrate that data in future analyses, mapping corrosion growth, and confirming data gathered by inline inspection tool. Develop and submit for approval a plan to perform internal inspections at regular intervals, not to exceed 5 years, and schedule for the repair of anomalies identified through those inspections. Implement that plan upon approval.

8. Perform infrared aerial surveys at already-established intervals for the entirety of the PBWOA, PBEOA, and Lisburne pipelines.

9. At the earliest practicable moment following discovery of any pipeline failure on the PBWOA, PBEOA, and Lisburne pipelines that involves the release of any amount of the hazardous liquid transported, give telephonic notice of the failure to the National Response Center in accordance with 49 C.F.R. § 195.52(b).

10. Submit for review each oil spill response plan developed pursuant to the requirements of Federal law or regulation for the PBWOA, PBEOA, and Lisburne pipelines.

The Director, Western Region, PHMSA may grant an extension of time for compliance with any of the terms of this Order for good cause. A request for an extension must be in writing.

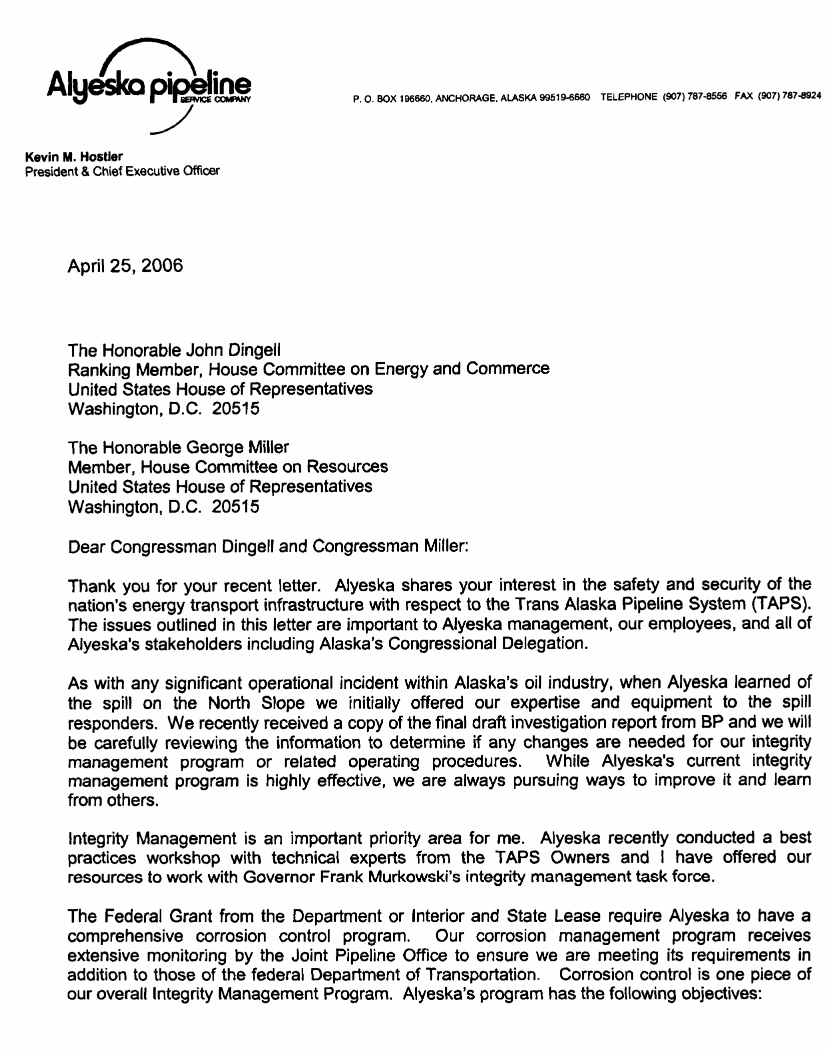
Respondent may appeal any decision of the Director, Western Region, PHMSA to the Associate Administrator for Pipeline Safety. Decisions of the Associate Administrator are final.

In accordance with 49 U.S.C. § 60122 and 49 C.F.R. § 190.223, failure to comply with this Order may result in the assessment of civil penalties of not more than $100,000 per day and in referral to the Attorney General for appropriate relief in a United States District Court.

MAR 15 2006

Stacey Gerard
Associate Administrator
for Pipeline Safety

Date Issued



Alyeska pipeline
SERVICE COMPANY

P. O. BOX 196660, ANCHORAGE, ALASKA 99519-6660 TELEPHONE (907) 787-8556 FAX (907) 787-8924

Kevin M. Hostler
President & Chief Executive Officer

April 25, 2006

The Honorable John Dingell
Ranking Member, House Committee on Energy and Commerce
United States House of Representatives
Washington, D.C. 20515

The Honorable George Miller
Member, House Committee on Resources
United States House of Representatives
Washington, D.C. 20515

Dear Congressman Dingell and Congressman Miller:

Thank you for your recent letter. Alyeska shares your interest in the safety and security of the nation's energy transport infrastructure with respect to the Trans Alaska Pipeline System (TAPS). The issues outlined in this letter are important to Alyeska management, our employees, and all of Alyeska's stakeholders including Alaska's Congressional Delegation.

As with any significant operational incident within Alaska's oil industry, when Alyeska learned of the spill on the North Slope we initially offered our expertise and equipment to the spill responders. We recently received a copy of the final draft investigation report from BP and we will be carefully reviewing the information to determine if any changes are needed for our integrity management program or related operating procedures. While Alyeska's current integrity management program is highly effective, we are always pursuing ways to improve it and learn from others.

Integrity Management is an important priority area for me. Alyeska recently conducted a best practices workshop with technical experts from the TAPS Owners and I have offered our resources to work with Governor Frank Murkowski's integrity management task force.

The Federal Grant from the Department or Interior and State Lease require Alyeska to have a comprehensive corrosion control program. Our corrosion management program receives extensive monitoring by the Joint Pipeline Office to ensure we are meeting its requirements in addition to those of the federal Department of Transportation. Corrosion control is one piece of our overall Integrity Management Program. Alyeska's program has the following objectives:

- Prevent leaks to protect public safety and the environment
- Comply with State and Federal regulations
- Manage risks – assess, prevent, or mitigate
- Preserve our assets thus providing reliable oil transportation
- Provide stakeholder assurance

The important point is that we have a comprehensive, systematic, and documented approach to integrity management, including corrosion monitoring and mitigation that is audited, both internally and externally.

In response to the questions raised in your letter, we offer the following answers:

1. *What knowledge do Alyeska officials have regarding the additive(s) that some in BP are suggesting has caused severe and rapid onset of corrosion on the main oil transit line (OTL) which recently leaked? Does Alyeska use any of such additives on its own line? If so, was corrosion at all associated with its use? Are these additives tested prior to use to insure that they do not have corrosive properties?*

   A. As noted above, we are currently evaluating BP's final draft investigation report and it would be premature to determine the implications of any additives for Alyeska at this point. The two additives used in the operation of TAPS are corrosion inhibitor and drag reducing agent (DRA). These additives do not cause a corrosive effect. The corrosion inhibitors are used to mitigate corrosive characteristics common to all crude oils. Prior to the public reports of the BP spill, Alyeska was unaware of the additives that BP referenced in its letter to you. BP has recently provided us with copies of material safety data sheets (MSDS) for the chemicals it introduces into the crude oil in Prudhoe Bay. We have reviewed the MSDS provided by BP. The MSDSs that were provided to us included a scale inhibitor, a corrosion inhibitor, a demulsifier, and a defoamer. We have reviewed the MSDS provided by BP, and the MSDS sheets do not indicate that any of these chemicals are corrosive in nature. All but one additive referenced in the MSDS sheets is related to production activities and would not be used by TAPS. One of the MSDS sheets described is a corrosion inhibitor similar to that used by TAPS, which does not cause corrosion.

2. *Has Alyeska determined if the additives used by BP on the OTL had any impact on TAPS, and if so, how and when was this determined?*

   A. As we are still reviewing and evaluating the final draft report about the spill and its causes, it is premature to discuss the role of additives in the BP spill and possible impact to TAPS. Alyeska is aware that chemical additives are used routinely in oil-field processing. We do not perform a physical analysis for the presence of additives, nor do we require such disclosure to us. Since our very recent learning of the possible risk of rapidly increased corrosion rates as seen in the BP spill, we have taken steps to ensure that we have a thorough understanding of this potential and are evaluating any possible next steps.

A significant mitigating factor with respect to the crude oil in TAPS is that the crude oil from BP's Prudhoe Bay Gathering Center Facility 1 is commingled with crude from other North Slope fields. The commingled stream enters TAPS at a velocity sufficiently high enough to keep water entrained in the crude oil. This prevents free water from settling out and creating an environment in which potential corrosion issues may develop. As a precautionary detection measure, I am accelerating our corrosion "smart" pig run that had been scheduled for 2007 to now perform that run this year. Additionally, we run cleaning pigs that clean any sediment, and wax from the pipe wall on a regular basis.

3. *Was Alyeska informed that additives would be added to upstream operations which could have some impact on the integrity of the TAPS? Is it common operator procedure to inform Alyeska of activities on feeder lines that may impact TAPS operations? If so, how was this done in this case?*

   A. Alyeska was not aware of the introduction of these additives to the Prudhoe Bay field crude stream; however, as stated above we are generally aware that additives are used and we do not require disclosure, nor do we routinely receive information from the North Slope field operators on crude oil stream characteristics.. We do routinely meet with them to discuss operational issues, like oil field or TAPS shutdowns for maintenance to attempt to find complementary timing. In addition, the fields routinely tell us of changes in flow rates or when they have operational upsets.

4. *What are Alyeska's methods (smart and maintenance pigging, etc.) and frequency of testing for corrosion on TAPS?*

   Alyeska does several specific things to prevent, identify, and manage corrosion:

   Prevention

- A cleaning pig is run along the length of TAPS every seven to fourteen days. This tool removes wax or other deposits that may accumulate on the mainline pipe walls.
- Corrosion inhibitor is injected in the deadlegs at the pump stations and Valdez Marine Terminal every two weeks. Pipes inside the Pump Stations that have no flow or stagnant areas are called deadlegs.
- Buried pipeline sections are coated and wrapped with tape to protect the steel from the environment. (Aboveground pipe has minimal external corrosion risk.)
- A cathodic protection (CP) system passively and actively protects the pipe's exterior from corrosion. The passive system uses sacrificial zinc and magnesium anodes which preferentially corrode and protect the pipeline (similar to the zinc anodes in home water tanks). The active system applies electrical current to the pipeline to prevent corrosion. There are 680 CP coupons and 1018 CP test stations placed along the pipeline to provide a quick way to measure CP levels. All of these are monitored annually.

Detection

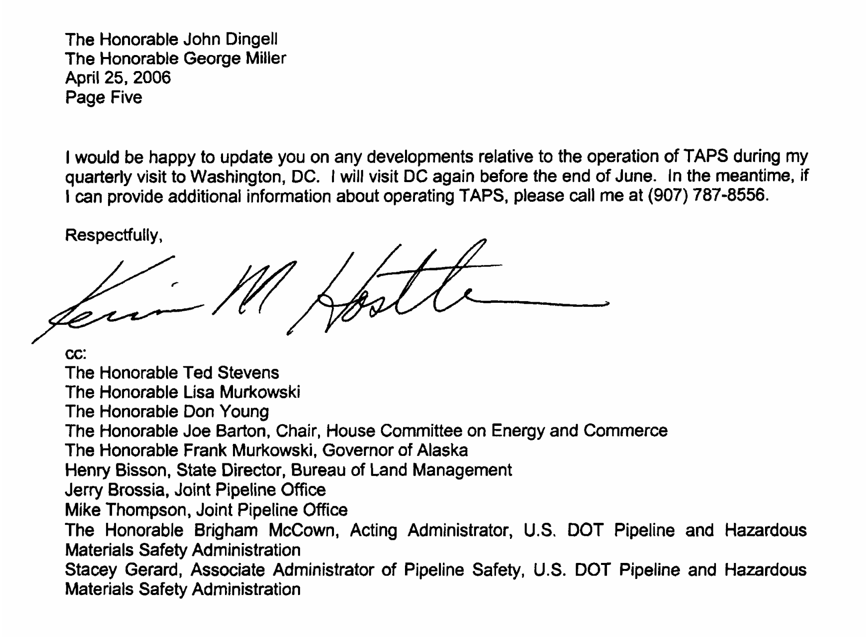
- A corrosion pig is run through the pipeline every three years. If there is evidence to suggest that a shorter interval is needed, more frequent runs can be performed. In the 29 years of TAPS operation, 60 instrumented pigs have been run. The most recent pig, run in 2004, provided over 99% pipe coverage.
- We have had a deadleg corrosion program since the early 1990's. This program includes a manual ultra sonic inspection of the dead legs on a regular basis. The frequency of the investigations are based on engineering analysis and calculated corrosion growth rates.
- Cathodic protection monitoring including CP coupons and close interval survey verifies the system data. This technique measures the electrical potential between the pipe and the surrounding soil to verify the CP system is working properly and meets National Association of Corrosion Engineers (NACE International) recommended practice. This survey is performed on one-third of the pipeline each year.
- Our facilities corrosion monitoring program includes the use of coupons to assess and monitor internal corrosion rates.

Corrosion Management

- Engineers use smart pig data to recommend pipeline repairs in advance of the DOT-mandated repair thresholds. The 2004 pig resulted in only six locations requiring further investigation.
- Areas not meeting NACE CP criteria are electrically adjusted and resurveyed the following year.
- Areas chronically failing to meet CP criteria are mitigated by capital improvements.
- Corrosion inhibitor injection in dead legs.

I appreciated the opportunity to discuss these issues directly with Chris Knauer while he was in Alaska the week of April 10th and I appreciated the discussions I had with Jeff Petrich while he was in Alaska at the end of January. We introduced Jeff and Chris to some of the professionals we employee to safely and successfully run TAPS and hope they can convey to you the dedication of our workforce.

In conclusion, it's important to point out that Alyeska operates its Integrity Management program through a controlled document (IM-244) titled, "TAPS Integrity Management Program for High Consequence Areas". I have read the entire document and am impressed by the breadth and depth of our program. If you are interested in reviewing a copy of the program, I would be happy to send it to you. This document is subject to periodic inspections by the U.S. Department of Transportation as a part of our DOT regulatory program.



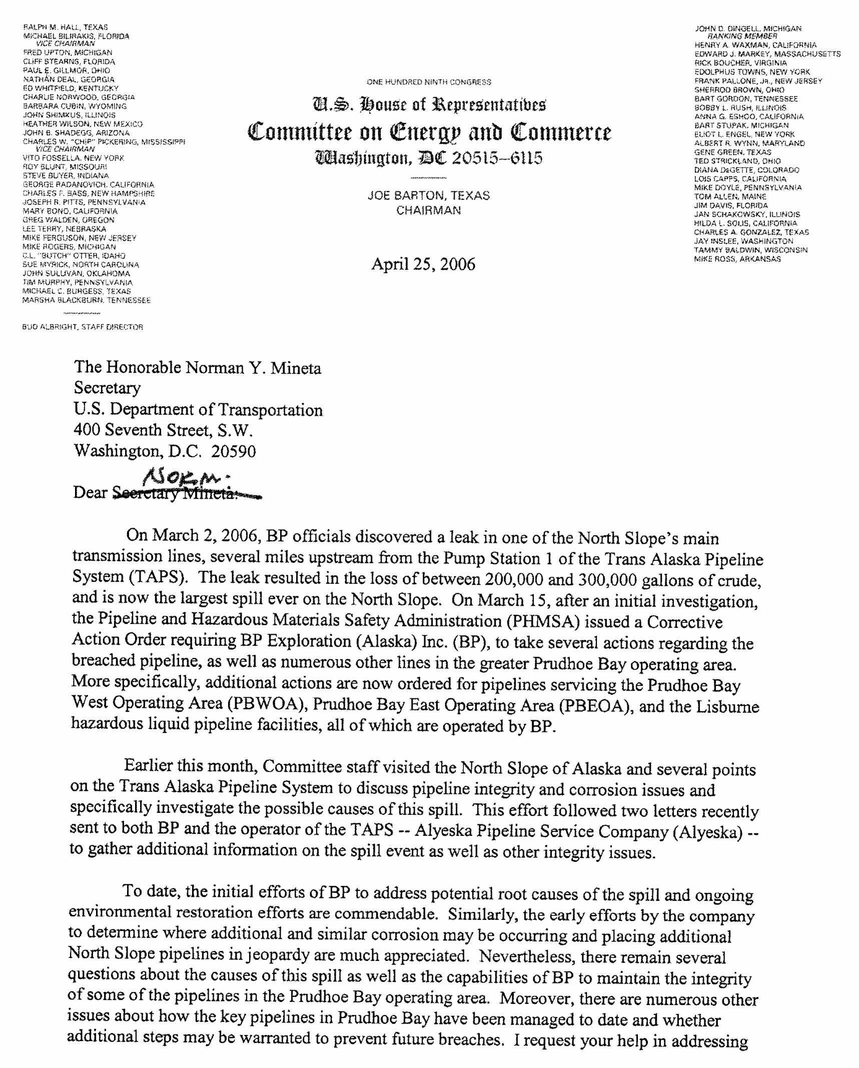
The Honorable John Dingell
The Honorable George Miller
April 25, 2006
Page Five

I would be happy to update you on any developments relative to the operation of TAPS during my quarterly visit to Washington, DC. I will visit DC again before the end of June. In the meantime, if I can provide additional information about operating TAPS, please call me at (907) 787-8556.

Respectfully,

Kevin M Hostler

cc:
The Honorable Ted Stevens
The Honorable Lisa Murkowski
The Honorable Don Young
The Honorable Joe Barton, Chair, House Committee on Energy and Commerce
The Honorable Frank Murkowski, Governor of Alaska
Henry Bisson, State Director, Bureau of Land Management
Jerry Brossia, Joint Pipeline Office
Mike Thompson, Joint Pipeline Office
The Honorable Brigham McCown, Acting Administrator, U.S. DOT Pipeline and Hazardous Materials Safety Administration
Stacey Gerard, Associate Administrator of Pipeline Safety, U.S. DOT Pipeline and Hazardous Materials Safety Administration



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U.S. House of Representatives
Committee on Energy and Commerce
Washington, DC 20515–6115

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April 25, 2006

The Honorable Norman Y. Mineta
Secretary
U.S. Department of Transportation
400 Seventh Street, S.W.
Washington, D.C. 20590

Dear ~~Secretary Mineta:~~ NORM:

On March 2, 2006, BP officials discovered a leak in one of the North Slope's main transmission lines, several miles upstream from the Pump Station 1 of the Trans Alaska Pipeline System (TAPS). The leak resulted in the loss of between 200,000 and 300,000 gallons of crude, and is now the largest spill ever on the North Slope. On March 15, after an initial investigation, the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a Corrective Action Order requiring BP Exploration (Alaska) Inc. (BP), to take several actions regarding the breached pipeline, as well as numerous other lines in the greater Prudhoe Bay operating area. More specifically, additional actions are now ordered for pipelines servicing the Prudhoe Bay West Operating Area (PBWOA), Prudhoe Bay East Operating Area (PBEOA), and the Lisburne hazardous liquid pipeline facilities, all of which are operated by BP.

Earlier this month, Committee staff visited the North Slope of Alaska and several points on the Trans Alaska Pipeline System to discuss pipeline integrity and corrosion issues and specifically investigate the possible causes of this spill. This effort followed two letters recently sent to both BP and the operator of the TAPS -- Alyeska Pipeline Service Company (Alyeska) -- to gather additional information on the spill event as well as other integrity issues.

To date, the initial efforts of BP to address potential root causes of the spill and ongoing environmental restoration efforts are commendable. Similarly, the early efforts by the company to determine where additional and similar corrosion may be occurring and placing additional North Slope pipelines in jeopardy are much appreciated. Nevertheless, there remain several questions about the causes of this spill as well as the capabilities of BP to maintain the integrity of some of the pipelines in the Prudhoe Bay operating area. Moreover, there are numerous other issues about how the key pipelines in Prudhoe Bay have been managed to date and whether additional steps may be warranted to prevent future breaches. I request your help in addressing some of these concerns and would appreciate your Department's response to the following questions by Tuesday, May 16, 2006:

1. The March 15 Corrective Action Order issued by PHMSA, requires that BP perform a number of maintenance procedures -- including the application of scraper pigs and smart pigs -- on several key lines serving the PBEOA and the Lisburne line. This region encompasses a number of key facilities including Flow Stations 1, 2, and 3 that eventually connect through a series of lines to Skid 50. Skid 50 is the last facility operated by BP before the transmission lines connect to PS 1 of TAPS. Item (7) of the attached Department of Transportation's (DOT) Corrective Action Order requires that BP:

   > "Perform an internal inspection using calibrated smart pig on the PBEOA and Lisburne pipelines within 3 months of receipt of this Order. Take appropriate action to address all anomalies discovered, in accordance with the standard for anomaly repair in 40 C.F.R Part 195. Record differences between inline inspection data and actual "as found" data for all anomalies and integrate that data in future analyses, mapping corrosion growth, and confirming data gathered by inline inspection tool. Develop and submit for approval a plan to perform internal inspection at regular intervals, not to exceed 5 years, and schedule for the repair of anomalies identified through those inspections. Implement that plan for approval."

   It is our understanding, however, that before implementing any internal inspection "using calibrated smart pig" -- as the order requires -- these lines must be first cleaned using a scraper pig to remove any buildup of sludge or other deposits that may have collected. In discussions with both Alyeska and BP officials, staff was informed that several key lines -- which appear to fall under the Corrective Order -- may not have been cleaned with a scraper pig since 1992. Additionally, other officials told staff that deposits of sludge may contribute to corrosion, particularly if the sludge traps a layer of water or the sludge prevents corrosion inhibitors from reaching and protecting the pipeline wall.

   (a) Does DOT share the view that sludge may be a contributing factor to corrosion (and thus pipeline integrity) and if so, how specifically?

   (b) What impact would the buildup of sludge or other material have on the effectiveness of corrosion-detection coupons?

2. Alyeska officials informed staff that the entire 800-mile TAPS is regularly cleaned with scraper pig once every 14 days.

(a) Is this DOT's understanding? And if so, what benefit does such scraping have on the integrity of this line or pipelines in general?

(b) What is DOT's understanding of the frequency of smart pigging on TAPS?

3. Staff was informed that several of the key lines serving the PBEOA (specifically the main transmission lines from Flow Stations 1, 2, and 3 that ultimately connect to Skid 50) and the Lisburne line have not been cleaned with a scraper pig, nor have they been examined with a smart pig, since as long ago as 1992. Moreover, staff was informed that these lines may now collectively contain considerable sludge and other buildup. In fact, company officials interviewed by staff said that there is potential for approximately 1,000 to 2,500 cubic yards of sludge to be removed from the pipelines that flow from Skid 50 to Flow Stations 1, 2, and 3.

   (a) What is DOT's understanding of the frequency in which the key lines that service the PBEOA, from Flow Stations 1, 2, and 3 to Skid 50 have been scraped with maintenance pigs. What is DOT's understanding of the frequency of smart pigging of these lines? Please also address the frequency of smart pigging and cleaning pigging for the Lisburne line.

   (b) At present, what is DOT's general understanding of the condition of all lines referenced in question 3(a)? Also, is it correct that at this point many of the lines in the PBEOA are deemed "indeterminate" by DOT?

   (c) Does DOT have an estimation of the amount of sludge buildup that may exist in these lines by volume measure? What is the process for removing large amounts of sludge and buildup should it exist?

   (d) Why does the entire 800-mile TAPS get scraper-pigged once every 14 days, yet many of the key lines that comprise the PBEOA have not been scraper pigged for perhaps as long as 14 years? Are there reasonable explanations for not scraper pigging these lines and does this length of time represent sound maintenance practices?

4. Staff was told by one official that previous attempts were made to operate scraper pigs on the major lines of the PBEOA (from Flow Stations 1, 2, and 3 to Skid 50) and the Lisburne line, yet some of these efforts were abandoned due to the volume of sludge being produced.

(a) Has DOT determined if earlier attempts were made to clean any or all these key lines and were significant amounts of sludge found?

(b) Has DOT asked for all documentation to show the maintenance history of those lines and any discussion regarding potential earlier difficulties in cleaning them due to high sludge or buildup volume?

(c) Does DOT even know the key results of these earlier pigging efforts?

5. Both Alyeska and BP officials told staff that if the sludge in these lines is considerable, the possibility exists that any maintenance pig sent through these lines might become stuck, which in a worst case scenario could result in the shutdowns of one or more flow stations.

(a) What is DOT's estimate of a pig "sticking" possibility?

(b) On what specific lines and in what location is this possibility greatest?

(c) Does DOT believe that cleaning these lines could result in a blockage that could result in the shutdown of one or more flow stations?

(d) Should the worst case scenario occur and flow stations are shut down, what is the implications for a "cold restart," given the time period DOT estimates such cleaning efforts will need to take place (e.g., potentially cold-weather months)?

6. If considerable amounts of sludge are discovered in these lines, how will that sludge be captured and disposed of? Some officials told staff that both the metering and strainers at TAPS's PS 1 may have to be bypassed due to anticipated volume. Staff was also told that one scenario would be to collect such sludge in the breakout tanks at PS 1. Another scenario would be to have BP collect the material at Skid 50 before the material makes it way to PS 1, yet currently there are no tanks available that could hold the possible volumes of this material. What is DOT's understanding of how this material will be handled, particularly if it is so voluminous? If the material is collected in the PS 1 breakout tanks, does that raise any safety or integrity issues for Alyeska and TAPS?

7. It is my understanding that BP Exploration (Alaska), Inc., had scheduled to smart pig the line that failed (and perhaps other key lines in the PBEOA) in 2006.

Nonetheless, there are now considerable engineering issues being "worked" to deal with the sludge problem and the potential for complications associated with running cleaning and maintenance pigs through at least some of these lines. Much of this engineering effort appears to be in its early stages. Moreover, until only recently senior officials from Alyeska appeared to know very little about the potential for downstream complications resulting from potential sludge. Given that the warmer (i.e., summer) months are approaching and this period of time is viewed as the most opportune time to run maintenance pigs through these lines, one would expect that key engineering questions about this effort would already be addressed.

(a) What evidence does DOT have regarding any scheduled pigging efforts planned for any of the lines covered by the Corrective Order that were in place prior to the rupture discovered on March 2, 2006?

(b) Has DOT asked BP for such evidence?

8. Recently, it was reported in the press that another line -- this time a small 3-inch gas pipe – also failed due to corrosion. According to press accounts, the volume of gas release in this line was too small to report to regulators. Nonetheless, we believe understanding the causes of this rupture may have some relevance to the current undertaking being pursued by DOT's Corrective Order.

(a) When, if at all, was DOT informed about this second rupture?

(b) Was this a potentially dangerous event to either the environment or workers? If so, how?

(c) Has DOT determined the causes of this failure? If so, please provide them.

At a time when crude oil prices are again reaching record-high levels and the supply is oil is tight, the soundness of the pipelines that serve the greater Prudhoe Bay operating area is critical to the Nation's national security. I appreciate DOT's efforts to work with BP, Inc., to make this operation as safe as possible and I thank you for your leadership on this important matter.

Should you have any additional questions regarding this request, please contact me, or have your staff contact Mr. Christopher Knauer of the Committee on Energy and Commerce Democratic staff at (202) 226-3400.

Sincerely,

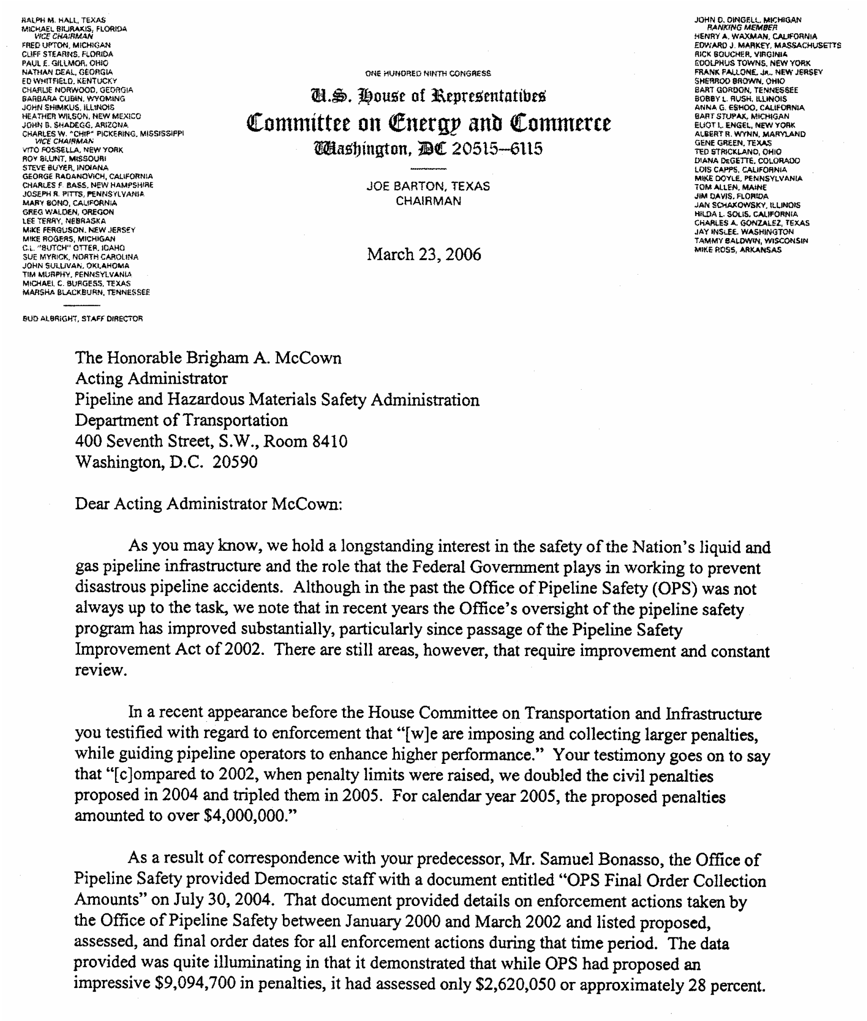
JOHN D. DINGELL
RANKING MEMBER

cc: The Honorable Joe Barton, Chairman
Committee on Energy and Commerce

The Honorable Kathleen Clarke, Director
Bureau of Land Management
U.S. Department of Interior

Mr. Jerry Brossia, Authorized Officer
The Joint Pipeline Office
Federal Bureau of Land Management - Alaska State Office

Mr. Kevin Hostler, President and Chief Executive Officer
Alyeska Pipeline Service Company



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TAMMY BALDWIN, WISCONSIN
MIKE ROSS, ARKANSAS

March 23, 2006

The Honorable Brigham A. McCown
Acting Administrator
Pipeline and Hazardous Materials Safety Administration
Department of Transportation
400 Seventh Street, S.W., Room 8410
Washington, D.C. 20590

Dear Acting Administrator McCown:

As you may know, we hold a longstanding interest in the safety of the Nation's liquid and gas pipeline infrastructure and the role that the Federal Government plays in working to prevent disastrous pipeline accidents. Although in the past the Office of Pipeline Safety (OPS) was not always up to the task, we note that in recent years the Office's oversight of the pipeline safety program has improved substantially, particularly since passage of the Pipeline Safety Improvement Act of 2002. There are still areas, however, that require improvement and constant review.

In a recent appearance before the House Committee on Transportation and Infrastructure you testified with regard to enforcement that "[w]e are imposing and collecting larger penalties, while guiding pipeline operators to enhance higher performance." Your testimony goes on to say that "[c]ompared to 2002, when penalty limits were raised, we doubled the civil penalties proposed in 2004 and tripled them in 2005. For calendar year 2005, the proposed penalties amounted to over $4,000,000."

As a result of correspondence with your predecessor, Mr. Samuel Bonasso, the Office of Pipeline Safety provided Democratic staff with a document entitled "OPS Final Order Collection Amounts" on July 30, 2004. That document provided details on enforcement actions taken by the Office of Pipeline Safety between January 2000 and March 2002 and listed proposed, assessed, and final order dates for all enforcement actions during that time period. The data provided was quite illuminating in that it demonstrated that while OPS had proposed an impressive $9,094,700 in penalties, it had assessed only $2,620,050 or approximately 28 percent.

Given this document and your recent testimony we would appreciate an update of the aforementioned chart containing the following:

1. (a) A detailed breakdown of penalty actions taken by OPS from March 7, 2002, to the present date, including types of violations for which a penalty was proposed; the proposed penalty; the assessed penalty; the amount collected for each final penalty; the reason, where applicable, for a reduction in the proposed penalty; the number of cases referred to the Department of Justice (DOJ) and the status of cases referred to DOJ.

   (b) The collection status of all final penalties for actions taken between January 1, 2000, and the present.

2. On June 21, 2001, OPS announced a proposed civil penalty in the amount of $2.52 million as a result of the pipeline incident in Carlsbad, New Mexico, that claimed the lives of 12 people. Please detail the status of this case, the final penalty assessed by OPS, and the collection status thereof.

3. In July of 2004, the Government Accountability Office (GAO) released a report entitled "Pipeline Safety: Management of the Office of Pipeline Safety's Enforcement Program Needs Further Strengthening"(GAO-04-801). This report contained a number of critical observations about OPS's enforcement program. I would appreciate specific responses to the following:

   (a) The GAO recommended that "OPS define its enforcement goals and strategy and establish a systematic approach for designing new performance measures." In her testimony before the Congress on March 16, 2006, Ms. Katherine Siggerud with GAO stated that "PHMSA has developed a reasonable enforcement strategy framework that is responsive to GAO's earlier recommendations." Please provide a copy of OPS's enforcement strategy and detail specifically how it differs from the enforcement regime in place at the time of the 2004 GAO report. Has this strategy been published or is it available on the OPS and/or PHMSA Web site. If not, why not?

   (b) Page 4 of the GAO report includes a discussion of OPS penalties assessed and reduced and notes that "OPS's database does not provide summary information on why penalties are reduced." Has OPS updated its database capabilities to include information on why proposed penalties are reduced? If so, please explain how this system works. If not, why not?

   (c) Page 13 of the GAO report states that "In 2002, OPS created an Enforcement Office to put more focus on enforcement and help ensure consistency in enforcement decisions. However, the agency has not yet filled key positions in this office." Please detail the number of full-time enforcement employees that are currently employed by OPS and the difference in staffing from July 2004.

(d) Page 33 of the GAO report noted several deficiencies in the method of penalty collection by OPS and the Federal Aviation Administration (FAA), which collects penalties on behalf of OPS. GAO made three specific recommendations that OPS should implement (p. 35) in order to improve the management of penalty collection which were (1) OPS should inform FAA of all proposed and assessed civil penalties so that FAA can carry out its collection functions; (2) FAA should share its reports on collections with OPS so that OPS will know the status of civil penalty enforcement actions; and (3) OPS should post all enforcement actions on its Web site, consistent with its policy.

Please comment on each specific recommendation and detail what actions OPS has taken to respond to each.

Because Congress is currently considering reauthorization of the Pipeline Safety Improvement Act of 2002, I would appreciate this information no later than Thursday, April 6, 2006. If you have any questions please contact me, or have your staff contact Mr. Bruce Harris of the Committee on Energy and Commerce Democratic staff at (202) 226-3400. Thank you for your attention to this matter.

Sincerely,

Rick Boucher

JOHN D. DINGELL
RANKING MEMBER
COMMITTEE ON ENERGY AND COMMERCE

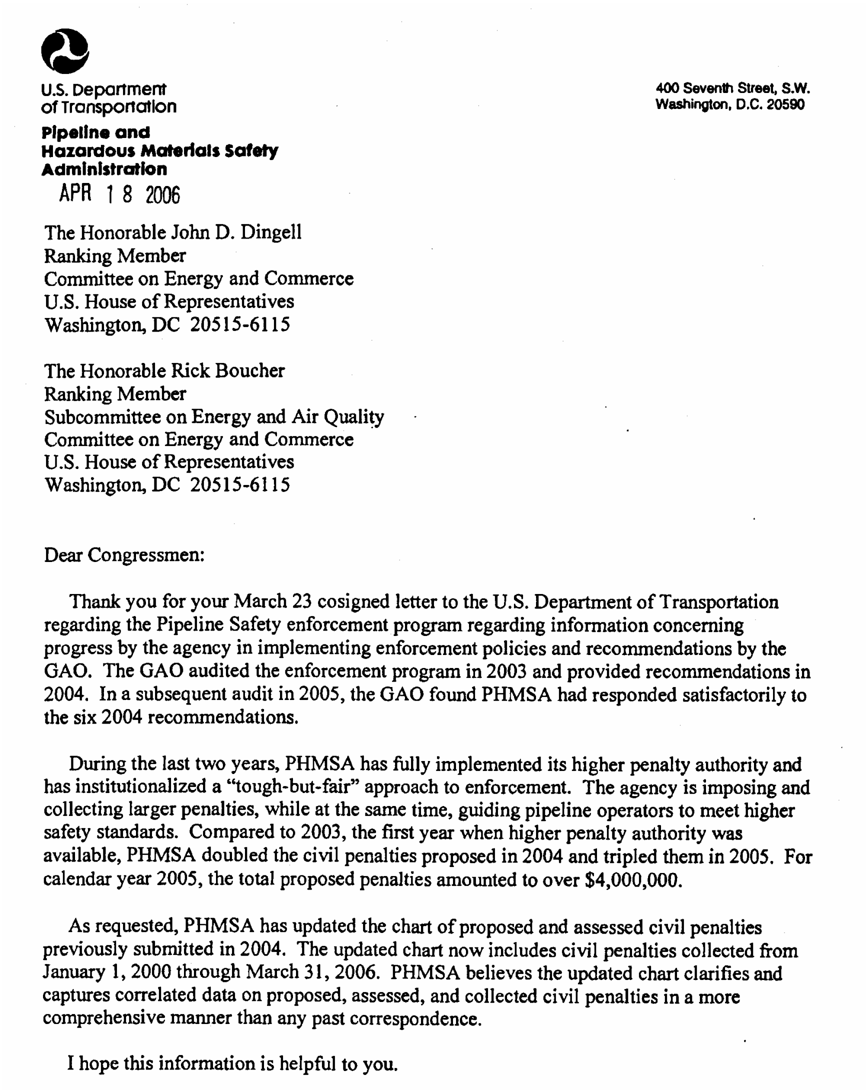
RICK BOUCHER
RANKING MEMBER
SUBCOMMITTEE ON ENERGY AND AIR QUALITY

cc: The Honorable Joe Barton, Chairman
Committee on Energy and Commerce

The Honorable Ralph M. Hall, Chairman
Subcommittee on Energy and Air Quality

The Honorable Don Young, Chairman
Committee on Transportation and Infrastructure

The Honorable James L. Oberstar, Ranking Member
Committee on Transportation and Infrastructure



U.S. Department
of Transportation
**Pipeline and
Hazardous Materials Safety
Administration**

400 Seventh Street, S.W.
Washington, D.C. 20590

APR 18 2006

The Honorable John D. Dingell
Ranking Member
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515-6115

The Honorable Rick Boucher
Ranking Member
Subcommittee on Energy and Air Quality
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515-6115

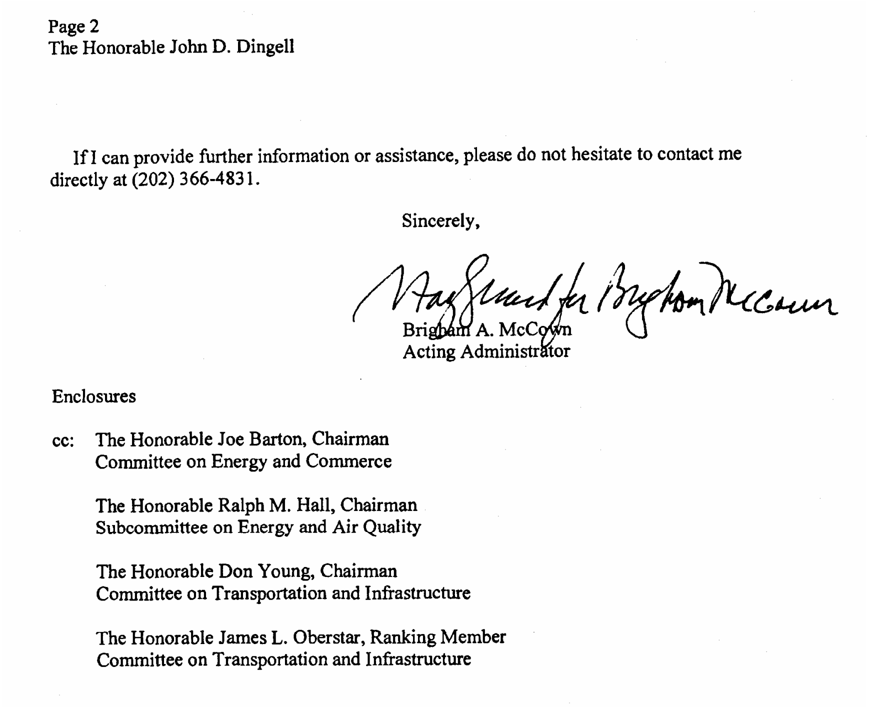
Dear Congressmen:

Thank you for your March 23 cosigned letter to the U.S. Department of Transportation regarding the Pipeline Safety enforcement program regarding information concerning progress by the agency in implementing enforcement policies and recommendations by the GAO. The GAO audited the enforcement program in 2003 and provided recommendations in 2004. In a subsequent audit in 2005, the GAO found PHMSA had responded satisfactorily to the six 2004 recommendations.

During the last two years, PHMSA has fully implemented its higher penalty authority and has institutionalized a "tough-but-fair" approach to enforcement. The agency is imposing and collecting larger penalties, while at the same time, guiding pipeline operators to meet higher safety standards. Compared to 2003, the first year when higher penalty authority was available, PHMSA doubled the civil penalties proposed in 2004 and tripled them in 2005. For calendar year 2005, the total proposed penalties amounted to over $4,000,000.

As requested, PHMSA has updated the chart of proposed and assessed civil penalties previously submitted in 2004. The updated chart now includes civil penalties collected from January 1, 2000 through March 31, 2006. PHMSA believes the updated chart clarifies and captures correlated data on proposed, assessed, and collected civil penalties in a more comprehensive manner than any past correspondence.

I hope this information is helpful to you.



Page 2
The Honorable John D. Dingell

If I can provide further information or assistance, please do not hesitate to contact me directly at (202) 366-4831.

Sincerely,

Stacey Gerard for Brigham McCown

Brigham A. McCown
Acting Administrator

Enclosures

cc: The Honorable Joe Barton, Chairman
Committee on Energy and Commerce

The Honorable Ralph M. Hall, Chairman
Subcommittee on Energy and Air Quality

The Honorable Don Young, Chairman
Committee on Transportation and Infrastructure

The Honorable James L. Oberstar, Ranking Member
Committee on Transportation and Infrastructure

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ENCLOSURE 1: RESPONSE TO QUESTIONS

In your letter you state, "Given this document and your recent testimony we would appreciate an update of the aforementioned chart containing the following:"

QUESTION: **1. (a) A detailed breakdown of penalty actions taken by OPS from March 7, 2002, to the present date, including types of violations for which a penalty was proposed; the proposed penalty; the assessed penalty; the amount collected for each final penalty; the reason where applicable, for a reduction in the proposed penalty; the number of cases referred to the Department of Justice (DOJ) and the status of cases referred to DOJ.**

ANSWER:

As stated in your March 23, 2006 letter, the agency submitted a document on July 30, 2004 that "provided details on enforcement actions taken by the Office of Pipeline Safety between January 2000 and March 2002 and listed proposed, assessed, and final order dates for all enforcement actions during that time period." An analysis of the data in the document led to the conclusion "while PHMSA had proposed an impressive $9,094,700 in penalties, it had assessed only $2,620,050 or approximately 28 percent." The data in 2004 for cases was not as complete as today to make a comprehensive comparison. A comparison today yields a much higher percentage. Also, we should not have included the Carlsbad, NM and the Bellingham, WA cases because we ultimately relied on a broader enforcement strategy outside the agency.

As requested, PHMSA prepared the following table, "Table 1: Penalty Actions for Cases with Final Orders, March 7, 2002 to March 31, 2006." This table specifically addresses the enforcement cases for which the agency assessed civil penalties in this time period. A penalty is assessed in a Final Order after opportunity for a hearing. PHMSA did not include the Carlsbad, NM and the Bellingham, WA cases in any of the charts that follow because PHMSA did not complete the prosecution. Where appropriate, PHMSA acts as part of a broader enforcement framework whose activities are brought together to achieve pipeline safety objectives. In the Bellingham case, PHMSA worked closely with other agencies to achieve a highly effective enforcement outcome. This incident underscores PHMSA's many enforcement tools and its ability to reach a good result in a variety of circumstances. The Carlsbad matter is currently pending and PHMSA is working toward a satisfactory resolution.

Based on the updated and more complete data of Table 1, the assessed-to-proposed civil penalty ratio is 77% for the 2000 to 2002 enforcement timeframe. As to the reasons for reduction of a penalty, PHMSA received from each operator, in all the listed cases, information or evidence, such as pipeline facility inspection or testing documentation, to warrant a change in the initial proposed civil penalty as the cases were administratively adjudicated. In the table, the last column shows cases for which an operator provided valid and sufficient evidence to warrant a penalty reduction, indicated by the letter A. Since each case stands upon a separate set of facts, the individual case determinations, and any instances where a reduction in penalties were given, are based upon individual case evaluations.

The violation types listed in Table 1 are general categories of pipeline activity requirements found in the Code of Federal Regulations applicable to pipeline safety. These violation types correlate to the dominant enforcement case citation. They are: Operations (O), Maintenance (M), Corrosion (Corrosion Ctrl), Pipeline Design (Design), Design of Components (Component), General Requirements (Segment Compliance), Construction (C), Operator Qualification (OQ), Drug & Alcohol (D&A), Training (T) and Welding of Steel Pipe (Welding).

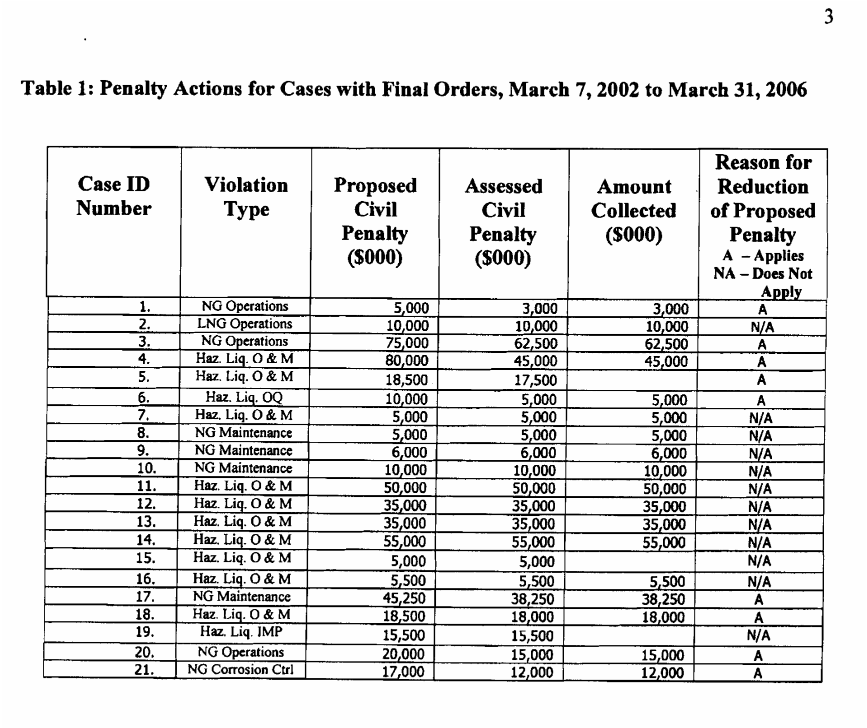


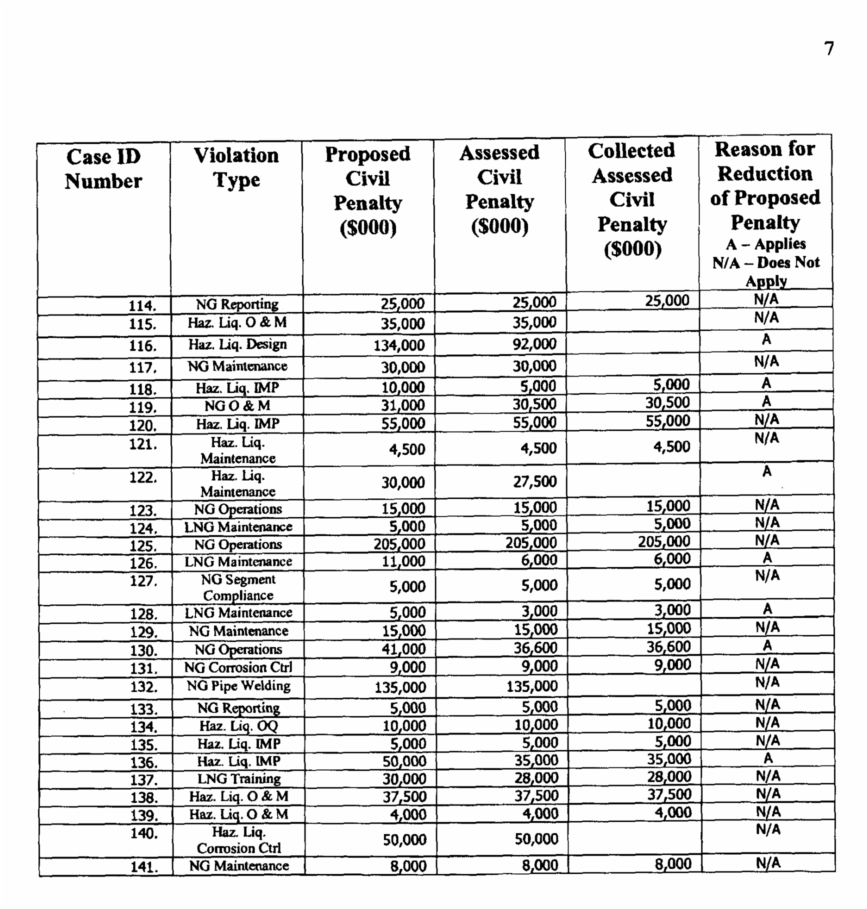
Table 1: Penalty Actions for Cases with Final Orders, March 7, 2002 to March 31, 2006

Case ID Number	Violation Type	Proposed Civil Penalty ($000)	Assessed Civil Penalty ($000)	Amount Collected ($000)	Reason for Reduction of Proposed Penalty A – Applies NA – Does Not Apply
1.	NG Operations	5,000	3,000	3,000	A
2.	LNG Operations	10,000	10,000	10,000	N/A
3.	NG Operations	75,000	62,500	62,500	A
4.	Haz. Liq. O & M	80,000	45,000	45,000	A
5.	Haz. Liq. O & M	18,500	17,500		A
6.	Haz. Liq. OQ	10,000	5,000	5,000	A
7.	Haz. Liq. O & M	5,000	5,000	5,000	N/A
8.	NG Maintenance	5,000	5,000	5,000	N/A
9.	NG Maintenance	6,000	6,000	6,000	N/A
10.	NG Maintenance	10,000	10,000	10,000	N/A
11.	Haz. Liq. O & M	50,000	50,000	50,000	N/A
12.	Haz. Liq. O & M	35,000	35,000	35,000	N/A
13.	Haz. Liq. O & M	35,000	35,000	35,000	N/A
14.	Haz. Liq. O & M	55,000	55,000	55,000	N/A
15.	Haz. Liq. O & M	5,000	5,000		N/A
16.	Haz. Liq. O & M	5,500	5,500	5,500	N/A
17.	NG Maintenance	45,250	38,250	38,250	A
18.	Haz. Liq. O & M	18,500	18,000	18,000	A
19.	Haz. Liq. IMP	15,500	15,500		N/A
20.	NG Operations	20,000	15,000	15,000	A
21.	NG Corrosion Ctrl	17,000	12,000	12,000	A

Case ID Number	Violation Type	Proposed Civil Penalty ($000)	Assessed Civil Penalty ($000)	Amount Collected for Each Final Civil Penalty ($000)	Reason for Reduction of Proposed Penalty A – Applies N/A – Does Not Apply
22.	Haz. Liq. O & M	43,800	0		A
23.	Haz. Liq. O & M	22,700	13,400	13,400	A
24.	Haz. Liq. IMP	43,000	43,000		N/A
25.	Haz. Liq. O & M	25,000	25,000	25,000	N/A
26.	Haz. Liq. O & M	5,000	5,000	5,000	N/A
27.	Haz. Liq. O & M	177,000	67,000	67,000	A
28.	NG Maintenance	34,000	34,000	34,000	N/A
29.	Haz. Liq. Accident Report	10,000	10,000		N/A
30.	Haz. Liq. O & M	3,000	3,000	3,000	N/A
31.	NG Maintenance	14,000	14,000		N/A
32.	NG Component Design	5,000	5,000		N/A
33.	NG Segment Compliance	15,000	15,000		N/A
34.	NG Maintenance	9,500	0		A
35.	NG Maintenance	24,500	9,500		A
36.	Haz. Liq. Construction	70,000	60,000	60,000	A
37.	Haz. Liq. O & M	182,500	101,000	101,000	A
38.	Haz. Liq. O & M	45,000	45,000	45,000	N/A
39.	Haz. Liq. O & M	8,500	8,500	8,500	N/A
40.	Haz. Liq. O & M	25,000	25,000	25,000	N/A
41.	Haz. Liq. Accident Report	5,000	5,000	5,000	N/A
42.	NG Corrosion Ctrl	554,000	400,000	400,000	A
43.	Haz. Liq. O & M	25,000	20,000	20,000	A
44.	Haz. Liq. O & M	25,000	25,000	25,000	N/A
45.	Haz. Liq. O & M	35,000	35,000	35,000	N/A
46.	Haz. Liq. OQ	50,000	16,000	16,000	A
47.	Haz. Liq. Design Requirements	30,000	20,000	20,000	A
48.	NG Corrosion Ctrl	5,000	5,000	5,000	N/A
49.	Haz. Liq. O & M	23,250	23,250	23,250	N/A
50.	LNG Training	220,000	30,000		A
51.	Haz. Liq. O & M	25,000	25,000	25,000	N/A
52.	NG Corrosion Ctrl	29,000	23,000	23,000	A
53.	NG Operations	20,000	20,000	20,000	N/A
54.	NG Operations	25,000	25,000	25,000	N/A
55.	Haz. Liq. IMP	5,000	0		A
56.	NG Operations	4,000	4,000		A
57.	Haz. Liq. O & M	5,000	5,000	5,000	N/A
58.	NG Maintenance	22,000	22,000	22,000	N/A

Case ID Number	Violation Type	Proposed Civil Penalty ($000)	Assessed Civil Penalty ($000)	Amount Collected for Each Final Civil Penalty ($000)	Reason for Reduction of Proposed Penalty A – Applies N/A – Does Not Apply
59.	Haz. Liq. O & M	5,000	5,000		A
60.	NG Corrosion Ctrl	70,000	70,000	70,000	N/A
61.	NG Corrosion Ctrl	83,750	83,750	83,750	N/A
62.	NG Maintenance	11,500	5,000		A
63.	NG Corrosion Ctrl	2,500	2,500		A
64.	NG Corrosion Ctrl	17,000	17,000	17,000	N/A
65.	Haz. Liq. Construction	30,000	25,000	25,000	A
66.	NG Operations	22,750	22,750	22,750	N/A
67.	Haz. Liq. IMP	110,000	90,000		A
68.	NG Operations	10,000	10,000	10,000	N/A
69.	Haz. Liq. IMP	25,000	25,000	25,000	N/A
70.	Haz. Liq. O & M	10,000	10,000	10,000	N/A
71.	Haz. Liq. O & M	10,000	10,000	10,000	N/A
72.	Haz. Liq. O & M	50,000	50,000	50,000	N/A
73.	Haz. Liq. IMP	5,000	5,000		A
74.	Haz. Liq. O & M	25,000	25,000		A
75.	NG Corrosion Ctrl	105,000	85,000	85,000	A
76.	NG Operations	126,000	86,000		A
77.	NG Operations	5,000	5,000	5,000	N/A
78.	NG Pipe Welding	10,000	10,000	10,000	N/A
79.	Haz. Liq. O & M	6,000	2,400	2,400	A
80.	NG Maintenance	10,000	0		A
81.	Haz. Liq. O & M	25,000	25,000	25,000	N/A
82.	Haz. Liq. O & M	25,000	25,000	25,000	N/A
83.	LNG Maintenance	5,200	4,900	4,900	A
84.	Haz. Liq. OQ	5,000	5,000	5,000	N/A
85.	NG Segment Compliance	20,000	12,500	12,500	A
86.	NG OQ	5,000	5,000	5,000	N/A
87.	Haz. Liq. O & M	2,500	2,500	2,500	N/A

Case ID Number	Violation Type	Proposed Civil Penalty ($000)	Assessed Civil Penalty ($000)	Amount Collected for Each Final Civil Penalty ($000)	Reason for Reduction of Proposed Penalty A – Applies N/A - Does Not Apply
88.	Haz. Liq. Materials	5,000	5,000		N/A
89.	Haz. Liq. O & M	10,000	10,000	10,000	N/A
90.	Haz. Liq. O & M	12,000	12,000	12,000	N/A
91.	NG Component Design	20,000	15,000	15,000	A
92.	Haz. Liq. Corrosion Ctrl	3,000	0		A
93.	Haz. Liq. O & M	7,000	7,000	7,000	N/A
94.	Haz. Liq. Design	90,000	40,000		A
95.	Haz. Liq. Construction	26,000	20,000	20,000	A
96.	Haz. Liq. O & M	20,000	20,000	20,000	N/A
97.	Haz. Liq. O & M	25,000	25,000	25,000	N/A
98.	Haz. Liq. O & M	20,000	20,000	20,000	N/A
99.	NG Maintenance.	92,000	92,000	92,000	N/A
100.	NG Maintenance	5,000	5,000	5,000	N/A
101.	NG Corrosion Ctrl	10,000	10,000	10,000	N/A
102.	Haz. Liq. O & M	12,750	12,750	12,750	N/A
103.	Haz. Liq. IMP	5,000	5,000	5,000	N/A
104.	Haz. Liq. O & M	15,000	15,000	15,000	N/A
105.	Haz. Liq. O & M	5,000	5,000	5,000	N/A
106.	Haz. Liq. IMP	105,000	105,000	105,000	N/A
107.	Haz. Liq. O & M	40,000	32,000	32,000	A
108.	Haz. Liq. O & M	50,000	25,000	25,000	A
109.	Haz. Liq. O & M	10,000	10,000	10,000	N/A
110.	Haz. Liq. Construction	60,000	60,000	60,000	N/A
111.	Haz. Liq. O & M	10,000	10,000	10,000	N/A
112.	Haz. Liq. O & M	10,000	7,500	7,500	A
113.	Haz. Mat. OQ	5,000	5,000		A



Case ID Number	Violation Type	Proposed Civil Penalty ($000)	Assessed Civil Penalty ($000)	Collected Assessed Civil Penalty ($000)	Reason for Reduction of Proposed Penalty A – Applies N/A – Does Not Apply
114.	NG Reporting	25,000	25,000	25,000	N/A
115.	Haz. Liq. O & M	35,000	35,000		N/A
116.	Haz. Liq. Design	134,000	92,000		A
117.	NG Maintenance	30,000	30,000		N/A
118.	Haz. Liq. IMP	10,000	5,000	5,000	A
119.	NG O & M	31,000	30,500	30,500	A
120.	Haz. Liq. IMP	55,000	55,000	55,000	N/A
121.	Haz. Liq. Maintenance	4,500	4,500	4,500	N/A
122.	Haz. Liq. Maintenance	30,000	27,500		A
123.	NG Operations	15,000	15,000	15,000	N/A
124.	LNG Maintenance	5,000	5,000	5,000	N/A
125.	NG Operations	205,000	205,000	205,000	N/A
126.	LNG Maintenance	11,000	6,000	6,000	A
127.	NG Segment Compliance	5,000	5,000	5,000	N/A
128.	LNG Maintenance	5,000	3,000	3,000	A
129.	NG Maintenance	15,000	15,000	15,000	N/A
130.	NG Operations	41,000	36,600	36,600	A
131.	NG Corrosion Ctrl	9,000	9,000	9,000	N/A
132.	NG Pipe Welding	135,000	135,000		N/A
133.	NG Reporting	5,000	5,000	5,000	N/A
134.	Haz. Liq. OQ	10,000	10,000	10,000	N/A
135.	Haz. Liq. IMP	5,000	5,000	5,000	N/A
136.	Haz. Liq. IMP	50,000	35,000	35,000	A
137.	LNG Training	30,000	28,000	28,000	N/A
138.	Haz. Liq. O & M	37,500	37,500	37,500	N/A
139.	Haz. Liq. O & M	4,000	4,000	4,000	N/A
140.	Haz. Liq. Corrosion Ctrl	50,000	50,000		N/A
141.	NG Maintenance	8,000	8,000	8,000	N/A

Case ID Number	Violation Type	Proposed Civil Penalty ($000)	Assessed Civil Penalty ($000)	Amount Collected for Each Final Civil Penalty ($000)	Reason for Reduction of Proposed Penalty A – Applies N/A — Does Not Apply
142.	NG O & M	335,000	275,000	275,000	A
143.	NG Corrosion Ctrl	5,000	5,000		N/A
144.	NG Operations	25,000	0		A
145.	NG OQ	80,000	30,000		A
146.	NG Corrosion Ctrl	7,500	7,500	7,500	N/A
147.	Haz. Liq. O & M	11,500	11,500	11,500	N/A
148.	Haz. Liq. O & M	12,000	12,000	12,000	N/A
149.	NG Reporting	5,000	0		A
150.	Haz. Liq. O & M	674,000	330,250	330,250	A
151.	Haz. Liq. O & M	6,200	6,200	6,200	N/A
152.	Haz. Liq. O & M	11,000	11,000		N/A
153.	Haz. Liq. IMP	10,000	5,000	5,000	A
154.	NG O & M	15,000	15,000	15,000	N/A
155.	Haz. Liq. O & M	70,000	70,000	70,000	N/A
156.	Haz. Liq. O & M	15,000	15,000		A
157.	Haz. Liq. O & M	10,000	10,000	10,000	N/A
158.	Haz. Liq. O & M	5,000	5,000	5,000	N/A
159.	Haz. Liq. O & M	3,600	3,600		N/A
160.	Haz. Liq. Drug and Alcohol	45,000	45,000		N/A
161.	NG Reporting	5,000	5,000	5,000	N/A
162.	NG Maintenance	9,500	4,500	4,500	A
163.	NG Maintenance	15,000	10,000		A
164.	Haz. Liq. O & M	22,000	0		A
165.	LNG Maintenance	45,000	30,000	30,000	A
166.	NG Maintenance	10,000	10,000	10,000	N/A
167.	NG Maintenance	36,500	36,500	36,500	N/A
168.	Haz. Liq. O & M	18,000	8,000		A

Case ID Number	Violation Type	Proposed Civil Penalty ($000)	Assessed Civil Penalty ($000)	Amount Collected for Each Final Civil Penalty ($000)	Reason for Reduction of Proposed Penalty A – Applies N/A – Does Not Apply
169.	NG Pipe Welding	15,000	15,000	15,000	N/A
170.	NG Operations	46,500	46,500	46,500	N/A
171.	NG Maintenance	9,000	9,000	9,000	N/A
172.	NG Maintenance	5,400	0		A
173.	NG Corrosion Ctrl	10,000	10,000		A
174.	NG Component Design	30,000	30,000	30,000	N/A
175.	Haz. Liq. Corrosion Ctrl	4,000	4,000	4,000	N/A
176.	Haz. Liq. Operations	6,000	6,000	6,000	N/A
177.	NG Maintenance	20,000	20,000	20,000	N/A
178.	NG Corrosion Ctrl	33,000	27,000	27,000	A
179.	NG Corrosion Ctrl	8,000	8,000	8,000	N/A
180.	Haz. Liq. Corrosion Ctrl	10,500	0		A
TOTALS		**6,433,150**	**4,928,600**		N/A

QUESTION: 1. (b) The collection status of all final penalties for actions taken between January 1, 2000, and the present.

ANSWER:

The agency developed Table 2 as a summary tabulation of calendar year proposed civil penalties directly related to the final collected fines, regardless of open cases with ongoing compliance orders. It covers civil penalties initiated between calendar year (CY) 2000 to March 31, 2006. However, open civil penalty cases or those in collection are excluded. In addition, the Bellingham, Washington accident and the Carlsbad, New Mexico incidents are not included in this tabulation because we are not listing any cases which the agency ultimately decided to handle with the Department of Justice. This adjustment provides a more realistic and consistent representation of PHMSA's civil penalty assessment and collection results.

The development of Table 2 requires a manual process to correlate a collected civil penalty to the year the agency proposed the civil penalty case. Civil penalty cases involve extensive processing. This process requires the agency to review an Inspector's evidence, provide the operator hearing time, and review the operator's evidence and analyze all data presented. Cases can take a year or more. PHMSA is in the process of automating systems for monitoring and measuring enforcement results, such as, tracking the number of inspection findings per 100 inspections where the findings indicate high risk to safety.

Finally, review of Table 2 indicates the following conclusions regarding PHMSA's collection of penalties for closed cases (closed means cases closed financially with payments collected by March 31, 2006):

- To date for CY2000 to CY2002, PHMSA collected an average of 75% of the fines proposed for closed cases. PHMSA closed an average of 91% of the cases during this period.

- To date for CY2003 to CY2005, PHMSA collected an average of 94% of the fines for closed cases. PHMSA closed an average of 56% of the cases during this period.

Table 2: Collection Status of all Final Penalties for Final Order Actions Taken Between January 1, 2000 to March 31, 2006[1]

Calendar Year (CY)	Number of Cases Opened in CY	Penalties Proposed in CY ($000)	Number of Cases Closed[2]	Penalties Proposed for Cases Closed[2] ($000)	Penalties Collected for Cases Closed[2] ($000)	Percent of Closed Cases[2]	Percent Collected of Amount Proposed
2000	20	1,319	19	1,189	816	95	69
2001	27	1,690	25	1,660	1,240	93	75
2002	47	1,764	40	1,280	1,047	85	82
2003	32	1,010	24	678	657	75	97
2004	63	2,220	38	732	700	60	90
2005	76	4,191	25	719	684	33	95

Note 1: This table excludes the Bellingham, Washington and Carlsbad, New Mexico cases.
Note 2: Closed means cases closed financially with payments collected by March 31, 2006

QUESTION: 2. On June 21, 2001, OPS announced a proposed civil penalty in the amount of $2.52 million as a result of the pipeline incident in Carlsbad, New Mexico, that claimed the lives of 12 people. Please detail the status of this case, the final penalty assessed by OPS, and the collection status thereof.

ANSWER:

It would be inappropriate for PHMSA to discuss the status because the Department of Justice is in non-public settlement discussions with respect to this matter.

QUESTION: 3. (a) The GAO recommended that "OPS define its enforcement goals and strategy and establish a systematic approach for designing new performance measures." In her testimony before the Congress on March 16, 2006, Mrs. Katherine Siggerud with GAO stated that "PHMSA has developed a reasonable enforcement strategy framework that is responsive to GAO's earlier recommendations." Please provide a copy of OPS's enforcement strategy and detail specifically how it differs from the enforcement regime in place at the time of the 2004 GAO report. Has this strategy been published or is it available on the OPS and/or PHMSA Web site. If not, why not?

ANSWER:

Prior to CY2004, the agency's pipeline safety enforcement program focused on the best ways to achieve operator compliance and to reduce incidents caused by non-compliance. The GAO in 2004 recommended PHMSA develop a process for pipeline safety enforcement, including goals, key strategies, and performance measures for program effectiveness.

In response, PHMSA developed a multi-year roadmap for strengthening enforcement, called the Enforcement Program Performance Plan. PHMSA established 14 strategies, and 37 specific actions in support of these strategies. PHMSA also defined 9 longer-term and 29 short-term performance indicators for measuring program effectiveness. For example, one key regulatory strategy is to deal severely with significant non-compliances and repeat offenses of any kind. To accomplish this, an example of a specific action is to develop guidance for the inspectors to use in ranking non-compliance by risk. These guidelines improve both external communication and internal analysis of pipeline safety performance. The risk ranking is an input in the enforcement action and civil penalty assessment process. The long term performance indicator for this strategy is risk-ranking operators within a peer group. We also identify high risk operators to plan more effective use of our inspection resources. The agency uses short term performance measurements to evaluate operator performance improvements or reduction in non-compliance severity as a result of a previous enforcement action.

Overall, the agency is improving its comprehensive process for tracking performance and advancing its measurement of enforcement effectiveness. As an enforcement mission goal, PHMSA seeks to reduce the number of incidents caused by non-compliance. As a part of this overall process, the agency is focusing resources on higher risks and poorer performing operators, with emphasis on critical issues to ensure effectiveness.

In its present form, the Enforcement Performance Plan is an internal agency document that guides enforcement strategy, a copy of which is attached. PHMSA is preparing a document for public consumption, intended for both informing pipeline operators and other stakeholders.

QUESTION: 3. (b). Page 4 of the GAO report includes a discussion of OPS penalties assessed and reduced and notes that "OPS's database does not provide summary information on why penalties are reduced." Has OPS updated its database capabilities to include information on why proposed penalties are reduced? If so, please explain how this system works. If not, why not?

ANSWER:

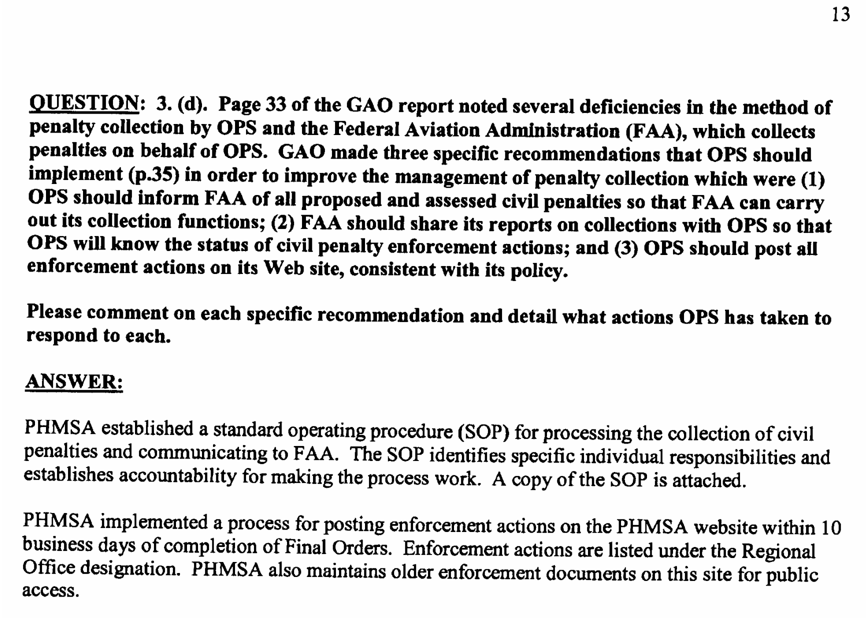
Yes, PHMSA completed the development of a new information system for enforcement tracking as a part of the Safety Monitoring and Reporting Tool (SMART) and is currently testing the system. When testing is completed, the SMART enforcement tracking system will capture all relevant civil penalty information contained in Final Orders. One of the benefits of this system is better integration of databases to analyze program performance and ad hoc reporting. PHMSA expects to use the SMART enforcement tracking as the system of record by CY2007.

QUESTION: 3. (c). Page 13 of the GAO report states that "In 2002, OPS created an Enforcement Office to put more focus on enforcement and help ensure consistency in enforcement decisions. However, the agency has not yet filled key positions in this office." Please detail the number of full-time enforcement employees that are currently employed by OPS and the difference in staffing from July 2004.

ANSWER:

PHMSA currently employs three engineers and six attorneys at headquarters who are solely dedicated to the pipeline safety enforcement program. These nine Federal employees apply enforcement policy and strive to achieve consistency in the work of 90 Federal and 400 State inspection and enforcement personnel.

Three enforcement positions have been added since 2004— a compliance officer and two pipeline attorneys. Since 2002, we have added two enforcement officers and five attorneys dedicated to pipeline safety enforcement, which account for a 350% increase in resources.



QUESTION: 3. (d). Page 33 of the GAO report noted several deficiencies in the method of penalty collection by OPS and the Federal Aviation Administration (FAA), which collects penalties on behalf of OPS. GAO made three specific recommendations that OPS should implement (p.35) in order to improve the management of penalty collection which were (1) OPS should inform FAA of all proposed and assessed civil penalties so that FAA can carry out its collection functions; (2) FAA should share its reports on collections with OPS so that OPS will know the status of civil penalty enforcement actions; and (3) OPS should post all enforcement actions on its Web site, consistent with its policy.

Please comment on each specific recommendation and detail what actions OPS has taken to respond to each.

ANSWER:

PHMSA established a standard operating procedure (SOP) for processing the collection of civil penalties and communicating to FAA. The SOP identifies specific individual responsibilities and establishes accountability for making the process work. A copy of the SOP is attached.

PHMSA implemented a process for posting enforcement actions on the PHMSA website within 10 business days of completion of Final Orders. Enforcement actions are listed under the Regional Office designation. PHMSA also maintains older enforcement documents on this site for public access.

MR. BOUCHER. Thank you, sir.

MR. HALL. I will ask just this last question.

Ms. Epstein, you stated in your testimony that high-consequence areas, or HCAs, as you all call them, are currently afforded the greatest regulatory oversight, a lot more attention. These areas are defined as hazardous transmission pipelines over commercially navigable waterways, high-population areas, in drinking water and ecological resources, and for natural gas transmission pipelines that cover high-density and other frequently-populated areas. However, I think you stated that this isn't enough, and you would like to see the definition of an HCA also include parks and refuges and fishable and swimable waters. I guess my question is if we change this definition, what areas are not considered HCAs? What would you leave out? And how would you propose the government prioritize its regulatory oversight if we defined every area as a high-consequence area?

MS. EPSTEIN. Yes.

MR. HALL. Lawyers say some kind of answer. The thing will speak for itself that all HCAs--go ahead.

MS. EPSTEIN. With due respect, Mr. Chairman, I don't believe that ever offended the NHCA, but it is important to remember that right now the industry is testing about 80 percent of its pipelines, so this would add some areas associated with public lands. Fishable and swimable waters are the clean water definition areas that do need to be protected, so we felt that it was important to bring that up.

That doesn't require, I believe, and I am not a lawyer, I am an engineer, a statutory change. If culturally and historic areas were included, that seems to be something that is not in the statute at this point. And I was a member of the Federal Advisory Committee when this was discussed and how broad should the regulatory definition be, and these issues were raised at that time. And in the interest of getting the rule out quickly, we focused--and some of us were in the minority who disagreed with the limited scope--but we did focus on the drinking water areas and the ecologically-relevant areas and the populated areas. And we said that is okay, but I think that it might make sense for PHMSA to go back and look at the transcript from those meetings where there was a promise made that there would be another look at some of these additional areas in the future.

MR. HALL. I think that concludes my questions.

Thank you all for your teaching, and thank you for your very good presentations and for your answers. And we will have some submissions to you, and I thank you for that.

MR. BOUCHER. Thank you.

MR. HALL. Well, we are adjourned.

[Whereupon, at 1:01 p.m., the subcommittee was adjourned.]

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